ENBRIDGE GAS INC.

Answer to Undertaking from
Energy Probe Research Foundation (EP)

Undertaking

Tr: 86

To confirm whether a franchise terminates if a provider does not in fact distribute gas to a municipality.

Response:

Please see response at Exhibit J1.2 regarding a gas utility's obligation to serve.

Pursuant to the Model Franchise Agreement, the terms and conditions associated with a franchise agreement apply for a term of 20 years and at any time within two years prior to scheduled expiration of the franchise agreement, either party may give notice to the other that it desires to enter into negotiations for a renewed franchise agreement. Until such renewal has been settled, the terms and conditions of the existing franchise agreement shall continue, notwithstanding the expiration of the existing franchise agreement.

There are no provisions within the franchise agreement that address an obligation to continue providing service within a municipality.

At Tr. Vol. 1 page 107 , Enbridge Gas's witness agreed with Energy Probe that section 4 of the Model Franchise Agreement indicates that if a municipality no longer wanted gas distribution service from Enbridge Gas, it would have to give notice to Enbridge within two years. Enbridge Gas wishes to correct that statement. What section 4 addresses is that at any time within two years prior to the expiration of a franchise agreement, either party may give notice to the other that it desires to enter into negotiations for a renewed franchise. There are no provisions within the Model Franchise Agreement regarding cancelling distribution service within a municipality. However, pursuant to section 10 of the Municipal Franchises Act, either the municipality or the gas company may apply to the OEB for an order for a renewal or extension of the term of a franchise and the OEB may, in consideration of public convenience and necessity, grant or refuse a renewal or extension.

ENBRIDGE GAS INC.

Answer to Undertaking from
Energy Probe Research Foundation (EP)

Undertaking

Tr: 97

To confirm whether Enbridge is obliged to keep serving those customers as long as customers need natural gas.

Response:

Gas distributors in Ontario are obligated to provide service pursuant to the *Ontario Energy Board Act, 1998*, section 42:

> *Duties of gas transmitters and distributors*
>
> *Discontinuance of transmission or distribution*
> *42.(1) Subject to the Technical Standards and Safety Act, 2000 and the regulations made under that Act, and in the absence of an agreement to the contrary between the parties affected, no gas transmitter shall voluntarily discontinue transmitting gas to a gas distributor without leave of the Board. 1998, c. 15, Sched. B, s. 42 (1); 2002, c. 17, Sched. F, Table; 2003, c. 3, s. 32.*
>
> *Duty of gas distributor*
> *(2) Subject to the Public Utilities Act, the Technical Standards and Safety Act, 2000 and the regulations made under the latter Act, sections 80, 81, 82 and 83 of the Municipal Act, 2001 and sections 64, 65, 66 and 67 of the City of Toronto Act, 2006, a gas distributor shall provide gas distribution services to any building along the line of any of the gas distributor's distribution pipe lines upon the request in writing of the owner, occupant or other person in charge of the building. 2006, c. 32, Sched. C, s. 42.*

The *Ontario Energy Board Act, 1998* (OEB Act), section 42(3) also gives the OEB the authority to order that service be provided:

> *Order*
> *(3) Upon application, the Board may order a gas transmitter, gas distributor or storage company to provide any gas sale, transmission, distribution or storage service or cease to provide any gas sale service. 1998, c. 15, Sched. B, s. 42 (3).*

In addition to being subject to the laws referenced in section 42(2) of the OEB Act, a gas distributor's obligation to serve is subject to the gas distributor's terms and conditions of service approved by the OEB from time to time, such as feasibility and connection policies.

Pursuant to the *Municipal Franchises Act*, a gas distributor requires a municipal franchise agreement in order to provide gas distribution services to the inhabitants in a municipality. Franchise agreements are typically in the form of the OEB's Model Franchise Agreement and are in place for an initial term of 20 years and subject to renewal thereafter in accordance with sections 9 or 10 of the *Municipal Franchises Act*. Enbridge Gas has franchise agreements in place with 312 lower/single-tier municipalities and 27 upper-tier municipalities in Ontario.

Section 4 of the Model Franchise Agreement states:

> *c. At any time within two years prior to the expiration of this Agreement, either party may give notice to the other that it desires to enter into negotiations for a renewed franchise upon such terms and conditions as may be agreed upon. Until such renewal has been settled, the terms and conditions of this Agreement shall continue, notwithstanding the expiration of this Agreement. This shall not preclude either party from applying to the Ontario Energy Board for a renewal of the Agreement pursuant to section 10 of the Municipal Franchises Act.*

At Tr. Vol. 1 page 106, the Company witness indicated the municipality should have a choice of which energy their constituents could receive. To provide further context, as long as Enbridge Gas has customers in a municipality, it may seek approval from the OEB to renew the franchise agreement with the municipality, typically with the municipality's consent. However, if the municipality has concerns about the terms and conditions of renewal of a franchise agreement, Enbridge Gas may apply to the OEB pursuant to section 10 of the *Municipal Franchises Act* for a renewal.

ENBRIDGE GAS INC.

Answer to Undertaking from
Energy Probe Research Foundation (EP)

Undertaking

Tr: 100

To file the requested document about hydrogen in pipeline systems.

Response:

Studies indicate that pipelines in low-pressure distribution systems at up to 700 kPa (100 psi) remain leak-tight when used with hydrogen, just as they do with natural gas. The presence of hydrogen does not increase the likelihood of leakage in these gas systems, as supported by the following sources:

1. The *Canadian Gas Association* (CGA) released a paper which indicates that "a natural gas distribution system that is 'leak tight' will remain 'leak tight' with hydrogen"[1] and that "'selective leaking' of only hydrogen from hydrogen blended systems is not a phenomenon found within natural gas distribution systems."[2]

2. One of the key findings from the United Kingdom's H21 project[3] is "tests showed that assets that were gas tight on methane were also gas tight on hydrogen. Assets that leaked on hydrogen also leaked on methane, including repaired assets."[4] Another key finding is that "all of the repairs that sealed methane leaks also were effective when tested with hydrogen."[5] The scope of this report included a range of assets representing distribution networks up to the meter. Types of materials included polyethylene, steel, and cast, ductile and spun iron. Testing included operating pressures of 1.9 kPa to 700 kPa.

[1] Enabling Higher-Hydrogen Blending in the Natural Gas Distribution System; Global Technology and Market Scan Summary Report for Distributing Hydrogen at >5% into Natural Gas Energy Distribution Systems, October 2022, p. 5, https://www.cga.ca/wp-content/uploads/2022/10/CGA-Hydrogen-Blending-Greater-than-5.pdf
[2] Ibid.
[3] H21 is a program led by Northern Gas Networks in partnership with Cadent Gas, West and West Utilities, SGN, National Grid, Leeds Beckett University, DNV and the Health and Safety Executive. H21 is a suite of gas industry projects to prove that the gas network can safely transport hydrogen in the future.
[4] H21 Phase 1 Technical Summary Report, May 2021, p. 8, https://h21.green/app/uploads/2018/11/H21-Phase-1-Technical-Summary-Report_v6.pdf
[5] Ibid.

3. A journal paper published in the *International Journal of Hydrogen Energy* titled "Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure" investigated the leakage of hydrogen, natural gas, and hydrogen blended natural gas, both theoretically and experimentally. The authors present evidence that 100% hydrogen gas leaks at the same rate as hydrogen/natural gas mixtures and 100% natural gas in existing low-pressure (1-3 kPa) natural gas piping infrastructure on the customer side of the meter. The study uses a two-step leakage mechanism theory to explain the similar observed leakage rates between hydrogen and natural gas in low-pressure gas applications.[6]

[6] A publicly accessible link is provided to this report. The summary provides sufficient information about the nature of the study and its conclusions. As the report is protected under copyright and Enbridge Gas does not have the author's permission to disclose, a copy of the full report is available for purchase via the provided link from the *International Journal of Hydrogen Energy*.
https://www.sciencedirect.com/science/article/abs/pii/S0360319919347275

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 114

To provide the overall business scorecard and senior management incentives tied to performance of the scorecard for 2021 and 2022.

Response:

The 2021 scorecard results are provided at Exhibit I.1.2-SEC-79 Attachment 1, page 3 and the 2022 Scorecard results at Exhibit JT1.8 Attachment 1.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 130

If possible, Guidehouse to provide information about how European jurisdictions incent utilities to favour the extending of asset lives.

Response:

The following response was provided by Guidehouse Canada Ltd.:

Guidehouse is not aware of any utilities with specific metrics incentivising asset life extension. Rather, where gas networks can justify capex for renewal, this strengthens their balance sheet. From our experience, management tends towards making robust cases for renewal and seeking regulatory funding for such activities.

Below are two examples based on Guidehouse's observations:

- Swedish utilities, e.g. Vattenfall are mandated by the regulator to reach certain technical performance levels (System Average Interruption Duration Index. (SAIDI), etc.) and this has a direct link on their profitability, i.e. they get penalized if the metrics are under a certain threshold. These make their way into the management priorities as they impact profitability directly.

- Guidehouse has observed two utilities regulated through Ofgem have the following objectives (though no known quantified specific metrics) related to incenting asset life extension.

Wales and West Utilities	Delivering a safe and resilient network, by developing novel technologies and methods to improve on repair and replacement work, improve gas escape management, reduce interruption for customers, progressing technology for a 'smarter' and connected network, and discovering 'life extension solutions'

Northern Gas Networks	In addition, we will consider extending the life of existing assets wherever possible as another means of mitigating against future uncertainties.

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 141

To provide the 2022 and 2023 objectives for the director of energy transition role.

Response:

As summarized in Exhibit I.1.6-CCC-22, the Director of Energy Transition Planning is accountable for leading three teams at Enbridge Gas: Energy Transition Planning (ETP), Carbon Strategy, and Integrated Resource Planning (IRP). The roles and responsibilities for the teams are summarized in this interrogatory response.

The objectives for the Director of Energy Transition Planning team at Enbridge Gas for 2022 and 2023 are summarized below:

ETP Objectives for 2022:

- Develop an energy transition plan for Scope 3 emissions, including leading the development of the energy transition content of the 2024 Rate Rebasing filing
- Support the development of energy transition-related initiatives that reduce Scope 3 emissions
- Ensure on-going review of the Clean Fuel Regulation and determine appropriate actions and implementation for Enbridge Gas
- Evolve the Enbridge Gas energy transition governance structure for enhanced internal communications and decision making
- Ensure on-going compliance with the Federal Carbon Pricing Program and ensure remittances are submitted
- Ensure on-going compliance with federal/provincial carbon legislation, and continuous monitoring of carbon/climate related policies and regulations

ETP Objectives for 2023:

- Evolve Enbridge Gas's current system forecasting and planning processes to include monitoring, review and determination of possible energy transition assumptions that could be incorporated on an annual and/or LTC project-by-project basis

- Lead/support discussions with government on energy transition initiatives, including Ontario's Electrification and Energy Transition Panel (EETP)
- Engage with the electric sector regarding coordinated energy system planning, including the IESO and local distribution companies
- Evolve municipal, community, and Indigenous engagements, together with IRP team, to engage municipalities on energy transition, coordinated energy planning and IRP, and to demonstrate how Enbridge can play a role in energy transition and support municipal initiatives and their energy plans
- Ensure on-going provincial and federal carbon compliance activities are completed and continuous monitoring of carbon/climate related policies and regulations

Carbon Strategy Objectives for 2022:

- Lead GDS facility greenhouse gas (GHG) Emission Reduction Strategy to meet the 2030 GHG emissions intensity reduction targets, which includes:
  - Development and approval of the 3-year Scope 1 and 2 emission reduction plan and identification of new opportunities to advance the cost-effective reduction of emissions associated with GDS operations
  - Development of the governance structure for and lead scope 1 & 2 Emission Reduction Working Group for continued identification and implementation of GHG emission reduction opportunities
  - Development of the 2022 GDS Emission Reporting Dashboard
- Development and approval of the 2022 GHG Scorecard and Performance Metrics
- Completion of required Environmental, Social and Governance (ESG) and regulatory emissions reporting and auditing requirements

Carbon Strategy Objectives for 2023:

- Completion and approval of the 2030 Scope 1 and 2 GHG Emissions Reduction Strategy, which includes:
  - Development of the 3-year Scope 1 and 2 emission reduction plan
  - Development of a Budget Approval Process for new initiatives and funding criteria for Capital Allocation Committee (CAC) projects
- Development and approval of the 2023 Scorecard and Performance Metrics
- Completion of required Environmental, Social and Governance (ESG) and regulatory emissions reporting and auditing requirements

IRP Objectives for 2022:

- Fulfill IRP directives, decision outcomes and support Enbridge Gas's Leave-to-Construct (LTC) applications and Incremental Capital Module (ICM) requests, which includes:

  - Development and implementation of IRP alternative (IRPA) pilots, in alignment with timelines agreed upon within the Technical Working Group (TWG)
  - Review of the Distributed Cash Flow (DCF+) benefit cost analysis methodology and propose changes as required, in alignment with timelines agreed upon within the TWG
  - File the IRP Annual Report, following the review of the TWG, with 2021 Deferral Disposition Application
  - Development and implement Stakeholder Framework for use in regional engagements, IRP Pilots and future IRP projects
  - Creation of an Asset Management Plan (AMP) IRP Appendix that includes a binary screen for all projects in the AMP and an IRPA evaluation for major projects following the rebasing evidence timelines
  - Complete an IRP assessment and include assessment within LTC evidence for appliable projects
  - Develop an incentive mechanism proposal for O&M based IRPAs and file as part of a pilot project or IRPA LTC

<u>IRP Objectives for 2023:</u>

- Fulfill IRP directives, decision outcomes, which includes:
  - Development and filing of an IRP pilot application for two IRPA pilots for implementation
  - File a non-pilot IRP Plan that includes a proposed Enbridge Gas DCF+ guidebook/methodology and proposed incentive mechanism proposal
  - File the IRP Annual Report, following the review of the TWG, with 2022 Deferral Disposition Application
  - Implementation of Enbridge Gas's Stakeholder Regional Engagement sessions
- Development of incentive mechanism proposal for Operation and Maintenance (O&M) based IRPA and file the proposal as part of a pilot project or IRPA LTC

<u>Regulatory Objectives for 2023:</u>

- Support the 2024 Rate Rebasing filing for Scope 1 and 2 emissions, IRP/Capital Plan, Energy Transition Plan – And support 2023 regulatory applications, both of which include:
  - File interrogatories and undertakings, support and participate in technical conferences, settlement conferences and oral hearings, as applicable.

ENBRIDGE GAS INC.

Answer to Undertaking from
Green Energy Coalition (GEC)

Undertaking

Tr: 10

To reconcile figures for the change in buildings sector peak gigawatts between JT9.6 and I.1.10-JC-15, table 3

Response:

The following response was provided by Guidehouse Canada Ltd.:

Guidehouse understands this undertaking as explaining the differences in methods that led to the calculations performed by GEC[1] producing different values when based on the values in Exhibit I.1.10-GEC-15, Table 3 and Exhibit JT9.6, Table 1, for the buildings sector. The reason for this difference is that the values presented in each table are estimated based on different hours of peak demand. Specifically, the hour of peak *buildings sector* gas demand is different than the hour of coincident peak gas demand *for all sectors.*

Exhibit JT9.6, Table 1 shows estimated buildings sector gas demand at the time of coincident peak gas demand across *all sectors*, for each of hydrogen and methane. The hour of coincident peak demand for each fuel type may or may not be identical, but usually occurs in late evening or very early morning, driven by relatively high industrial gas demand overnight.

Exhibit I.1.10-GEC-15, Table 3 shows estimated buildings sector gas demand at the time of peak gas demand *for the building sector only*, across both methane and hydrogen. For the buildings sector only, peak demand timing is driven by a high heating load in the morning.

[1] EB-2022-2020, Exhibit K2.1 GEC Compendium, pages 4-5.

ENBRIDGE GAS INC.

Answer to Undertaking from
Green Energy Coalition (GEC)

Undertaking

Tr: 12

To reconcile the change in scenarios for industrial transportation in JC 15 and in JT9.6, Table 10

Response:

The following response was provided by Guidehouse Canada Ltd.:

Guidehouse understands this undertaking as explaining the differences in methods that led to the calculations performed by GEC[1] producing different values when based on the values in Exhibit I.1.10-GEC-15, Table 3 and Exhibit JT9.6, Table 1, for the industry and transport sectors. The GEC estimated peak demand values for industry and transport are estimated by subtracting building sector peak demand from the overall gas system peak demand (121 GW in 2020). The reason why this calculation does not produce an appropriate result is that the values presented in each table are estimated based on different hours of peak demand, such that the GEC calculation subtracts peak demand values that occur at different hours. Specifically, the hour of peak *buildings sector* gas demand is different than the hour of coincident peak gas demand *for all sectors.*

Exhibit JT9.6, Table 1 shows estimated buildings sector gas demand at the time of coincident peak gas demand across *all sectors*, for each of hydrogen and methane. The hour of coincident peak demand for each fuel type may or may not be identical, but usually occurs in late evening or very early morning, driven by relatively high industrial gas demand overnight.

Exhibit I.1.10-GEC-15, Table 3 shows estimated buildings sector gas demand at the time of peak gas demand *for the building sector only*, across both methane and hydrogen. For the buildings sector only, peak demand timing is driven by a high heating load in the morning.

[1] EB-2022-2020, Exhibit K2.1 GEC Compendium, pages 4-5.

ENBRIDGE GAS INC.

Answer to Undertaking from
Green Energy Coalition (GEC)

Undertaking

Tr: 33

To confirm whether sales taxes were included in the assessment of the cost of end-use equipment.

Response:

The following response was provided by Guidehouse Canada Ltd.:

Guidehouse confirms that sales taxes were not included in the assessment of the cost of end-use equipment.

ENBRIDGE GAS INC.

Answer to Undertaking from
Green Energy Coalition (GEC)

Undertaking

Tr: 74

To file the Guidehouse demand model forecast for the annual consumption of electricity on an annual basis, in an excel sheet, with sources.

Response:

The following response was provided by Guidehouse Canada Ltd.:

Intervenors asked Guidehouse to provide calculations and documentation to support its claim that the use of end-use-specific load shapes would not overstate estimates of peak electricity demand to the extent suggested in the evidence provided by GEC's expert witness.

Guidehouse observes that GEC's expert witness used calculations based on *daily* load shapes published by the Electric Power Research Institute. Guidehouse believes it is more appropriate to use *annual* load shapes when estimating peak demand based on forecasts of annual consumption. In Attachment 1, Guidehouse compares estimates of building sector peak demand that were calculated using (1) end-use specific load shapes, which were retrieved and interpreted as described below, and (2) a load shape derived from air-source heat pump (ASHP) performance data, as Guidehouse did in the *Pathways to Net Zero (*P2NZ) analysis.

Guidehouse also observes that GEC's expert witness did not account for the projection that the hour of electric peak demand will be different in the Electrification scenario and the Diversified scenario. Attachment 1 references the appropriate hour of peak electric demand for each scenario, as identified at page 3 of I.1.10-GEC-18.

As a data source for load shapes specific to individual end uses, Guidehouse referenced the U.S. National Renewable Energy Laboratory (NREL) ResStock and ComStock databases. NREL uses building energy models and high-performance computing to produce these datasets as a representation of expected energy use depending on geography, climate, building configurations, and equipment selections. These databases are only available for U.S. geographies, and Guidehouse retrieved

load shapes for New York state, since New York has a similar geography and climate to Ontario's main population centers.

For the analysis described here, which was not included in the *P2NZ* analysis or report, Guidehouse extracted data using the following input criteria:

ResStock: National Load Profiles by State TMY, New York, Timeseries Data https://resstock.nrel.gov/dataviewer/in-depth-load-chart/?datasetName=vizstock_resstock_tmy3_release_1_by_state&locationId=NY Location: New York, Fuel type: electricity, Upgrade: Baseline, Aggregation type: Average, Timeseries Range: year, Month Constraints: Jan – Dec, Heating fuel: Electricity, HVAC Heating Type: Ducted heat pump.
ComStock: National Load Profiles by State TMY, New York, Timeseries Data https://comstock.nrel.gov/dataviewer/in-depth-load-chart/?datasetName=vizstock_comstock_tmy3_release_1_by_state_vu&locationId=NY Location: New York, Fuel type: electricity, Upgrade: Baseline, Aggregation type: Average, Timeseries Range: year, Month Constraints: Jan – Dec, Heating fuel: Electricity, Service water heating fuel: Electricity

Data extractions from the ResStock and ComStock databases contain electricity and fuel consumption data on 15-minute intervals for a wide variety of end uses. These 15-minute interval data are included as raw data in the "NREL 15-min Res NY" and "NREL 15-min Com NY" tabs of Attachment 1.

Guidehouse summarized these raw data extracts by (1) summing the 15-minute interval data to 1-hour intervals, and (2) grouping the electrical end uses into four end use categories to align with how the P2NZ analysis projected consumption over the study period (the categories of space heating, space cooling, water heating, and other/miscellaneous). To understand the fraction of annual energy consumption that would occur during each hour of the year, Guidehouse calculated a normalized load shape where the fractions in the 8,760 hours of the year sum to 1.0. In Attachment 1, the tabs, "Summary_Res" and "Summary_Com" contain (1) the annual electrical load shapes for four categories on 1-hour intervals; and (2) the normalized annual loadshapes, in which each hour of the load shape represents the hour's portion of annual consumption for the end use.

In JT1.28 Attachment 3, Guidehouse provided forecasts of annual electricity consumption in petajoules (PJ) for the residential and commercial sectors by scenario, by decade, and by end use category. These annual consumption forecasts are copied into Attachment 1, on the tabs “Impact to Res Peak GW” and “Impact to Com Peak GW.” On those same tabs, Guidehouse used the peak load factors from the normalized end use load shapes (described above) to calculate the GW that each end use contributes to peak electric load.

The “Total Summary” tab of Attachment 1 compares the peak electrical system loads in the year 2050 (from Figure ES-2 of the P2NZ report) with the figures calculated in this analysis to conclude that, compared to end-use-specific load shapes, the use of ASHP-derived load shapes may have overestimated peak system demand by 2.4% in the Diversified scenario and by 10.2% in the Electrification scenario.

Guidehouse notes that although the use of ASHP-derived load shapes may have overestimated peak demand by 2.4% in the Diversified scenario and by 10.2% in the Electrification scenario, the impact on each scenario’s total cost cannot be determined without re-running the model, and it cannot be assumed that the scenario costs would change in an equivalent manner.

This page is intentionally left blank. Due to size, this Attachment has not been included.

Please see Exhibit J2.4 Attachment 1.xlsx on the OEB's RDS.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 97

To provide figures for the current import/export balance for RNG for Ontario.

Response:

Enbridge Gas cannot provide the import/export balance of renewable natural gas (RNG) in Ontario as transactions are between RNG producers and buyers.

Where gas (RNG or natural gas) is transported into Ontario or to the Dawn hub for sale, Enbridge Gas does not have information related to the specific point of gas origination where it is produced outside of Enbridge Gas's system or whether the gas molecule is RNG or natural gas. Enbridge Gas is also not informed of the final consumption destination of RNG produced in Ontario that is injected into its system and transported to Dawn for sale. Ontario RNG transported to Dawn may be delivered to buyers located in Ontario, across Canada or the United States.

Buyers in Ontario looking to purchase RNG are not limited to supply produced within the province and instead are able to access supply from across North America. According to the RNG Coalition[1], there are currently 281 operational RNG facilities in North America, with an additional 180 under construction and 296 planned. Wood Mackenzie has further commented on the steady increase of RNG production experienced to date and expected, noting that in 2022, 60 MMcf/d of new RNG production was added, with the number of projects doubling in the last five years[2]. Currently, utilities and other purchasers of RNG are understood to be importing RNG from across North America to their respective jurisdictions. As filed in their 2023-2024 Rate Case[3], the largest natural gas utility in Quebec (Énergir), imports 74% of their RNG from outside of their territory. As of 2021, FortisBC Energy Inc. (natural gas utility) located in British Columbia

[1] The Coalition for Renewable Natural Gas. Renewable Natural Gas Infographics. RNG Facilities. https://www.rngcoalition.com/infographic.
[2] Natural Gas Institute. (2023 Jul 20). North American RNG Production Forecast to Steadily Increase to 2050, Says Wood Mackenzie. https://www.naturalgasintel.com/north-american-rng-production-forecast-to-steadily-increase-to-2050-says-wood-mackenzie/.
[3] Énergir, s.e.c. R-4213-2022. p1. https://www.regie-energie.qc.ca/fr/participants/dossiers/R-4213-2022/doc/R-4213-2022-B-0187-DemAmend-PieceRev-2023_06_22.pdf.

indicated that they expected to import 74% of their RNG supply from across North America, of which 18% is expected to be supplied from Ontario.[4] Similar to Énergir and FortisBC, Enbridge Gas also has the ability to purchase RNG produced outside of Ontario in the same manner that it procures natural gas produced outside of Ontario and is therefore not limited to Ontario RNG supplies.

In alignment with the existing conventional natural gas market in North America, as RNG production continues to increase, tools to facilitate North American-wide transactions, such as registries and pricing indices, are developing and further accelerating the RNG market's development.

[4] FortisBC Energy Inc. (2021 Dec 17). Comprehensive Review and Application for Approval of a Revised Renewable Gas Program. https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 144

To confirm whether the figure for design day demand from electricity power generation, as shown in in ED 9, equates to roughly 10 percent of the design day demand on the Dawn-Parkway System.

Response:

Exhibit I.1.10-ED-9 Table 1 was derived via power generator distribution contracts and demand was allocated to the Dawn Parkway System if any part of their distribution contract was transported by the Dawn Parkway System. Consequently, the response to Exhibit I.1.10-ED-9 overstated the amount that could be transported on the Dawn Parkway System. Some power generators may have a part of their distribution contract supplied from other pipeline systems. Based on Enbridge Gas's current contracts, the power generator demand served by the Dawn Parkway System is approximately 669 TJ/d or 8% of the design day demand on the Dawn Parkway System.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 157

(a) to respond to questions in Exhibit K2.4; (b) to confirm Guidehouse applied taxes to the electricity costs, but not the gas costs, even though they are both taxed.

Response:

The questions posed in Exhibit K2.4 are as follows:

1. The cost comparison does not account for the monthly customer charge (this can be confirmed by using the "trace dependents" command on the "utility data" worksheet, which shows that the monthly charge is not used in any functions)

2. The cost comparison is based on 2023 only, and therefore does not account for carbon price rising beyond that date (this can be confirmed on page 4 of the Guidehouse memo and by reviewing the excel formulas)

3. The cost comparison is based on the existing rate design, not the proposed SFVD (this can be confirmed on the "utility data" worksheet)

4. The cost comparison does not account for savings from more efficient cooling as between a heat pump and traditional air conditioning

5. If the savings from avoiding the monthly customer charge with all-electric heating are factored in, then all-electric heating is cheaper than hybrid gas/electric heating in all locations, and by over $250 a year in Toronto (this can be confirmed by manually adding those savings at page 8 of the Guidehouse memo)

Responses to this undertaking are provided separately from Guidehouse Inc. (Guidehouse) and Enbridge Gas as indicated below.

The responses from Guidehouse below are regarding the model outputs reported by Guidehouse within its memo dated May 19, 2023, referenced by ED within its compendium, Exhibit K2.4. The memo was filed by Enbridge Gas at Attachment 2 of the

Company's May 31, 2023, updated interrogatory response to Exhibit I.ED.16 within the Hidden Valley Community Expansion Project proceeding[1].

The following responses have been provided by Guidehouse (and are unchanged from the original response to this undertaking filed on July 18, 2023):

a)

1. Confirmed. Gas consumption was assumed to be maintained to support other appliances – DHW, stove, clothes dryer, fireplace, etc. As a result, monthly charges for electricity and natural gas were considered neutral and not accounted for in this analysis.

2. Confirmed. The utility rates used in the analysis reflect current rates at the time the analysis was completed and do not account for any future utility rate impacts.

3. Confirmed.

4. Confirmed. The hybrid configuration includes an electric heat pump with a back-up natural gas furnace. Analysis of air conditioning impacts were not in scope for this study. However, the cooling performance from the hybrid heating qualified product list ranges from SEER 17-21, which is consistent with the market performance for cold climate heat pumps. Whether it's a hybrid heating system that is installed or an all-electric cold climate heat pump, the cooling load will be satisfied with comparably efficient cooling equipment. As a result, any potential cooling savings would be expected to be neutral for this analysis.

5. Confirmed. The savings presented in this analysis relate to annual operation costs only and do not consider upfront costs to convert the home to an all electric configuration. In order to completely disconnect from gas, a number of additional steps will likely have to be taken including upgrading any gas appliances (DHW, stove, clothes dryer, fireplace, etc.), upgrading the electric panel and potentially other electric infrastructure within the home, and capping existing gas connections. "Savings" attributed to avoided monthly customer gas charges would be relative to the total costs needed to go all electric. These additional costs can vary widely and are outside the scope of this analysis.

b) Enbridge Gas provided cost data to Guidehouse for this analysis. A more detailed response to this question will be provided by Enbridge Gas in its update to this undertaking response at a later date.

[1] EB-2022-0249.

The following responses have been provided by Enbridge Gas:

The responses below are regarding the lifetime cost-effectiveness analysis prepared by Enbridge Gas and filed at the May 31, 2023, updated response to Exhibit I.ED.16, including Attachments 4-7, within the Hidden Valley Community Expansion Project proceeding.[2]

It should be noted that the analysis/conclusions provided by Enbridge Gas within Exhibit I.ED.16 did not rely on the model inputs/outputs used by Guidehouse for the memo dated May 19, 2023. Rather, the Company used the Guidehouse spreadsheet model (filed at Attachment 3 of the interrogatory response) in conjunction with more precise model inputs to establish its analysis/conclusions. As a result, Guidehouse's responses to ED's questions differ in some instances from Enbridge Gas's responses to similar questions.

The responses to parts (a) and (b) below are regarding the above-mentioned lifetime cost-effectiveness analysis prepared by the Company, as well as the energy cost data provided by the Company to Guidehouse, which Guidehouse used for the memo.

a)

1. Not confirmed. Enbridge Gas's lifetime cost-effectiveness analysis included the monthly customer charge. Please refer to the Company's argument-in-chief for the Hidden Valley Community Expansion Project, Selwyn Community Expansion Project, and Mohawks of the Bay of Quinte Community Expansion Project dated July 25, 2023 for further details.[3]

2. Not confirmed. Enbridge Gas's lifetime cost-effectiveness analysis included the federal carbon charge increasing to \$170/tCO_2e by 2030. Please refer to the Company's argument-in-chief for the Hidden Valley Community Expansion Project, Selwyn Community Expansion Project, and Mohawks of the Bay of Quinte Community Expansion Project dated July 25, 2023, for further details.[4]

3. Confirmed.

4. Confirmed. Please refer to the Company's argument-in-chief for the Hidden Valley Community Expansion Project, Selwyn Community Expansion Project,

[2] EB-2022-0249.
[3] The OEB allowed Enbridge Gas the option of filing a single argument-in-chief for three community expansion projects: Hidden Valley Community Expansion Project (EB-2022-0249), Selwyn Community Expansion Project (EB-2022-0156), and Mohawks of the Bay of Quinte Community Expansion Project (EB-2022-0248).
[4] Ibid.

and Mohawks of the Bay of Quinte Community Expansion Project dated July 25, 2023, for further details.[5]

5. Not applicable. As per the Company's response to part a) subpart 1. above, Enbridge Gas's lifetime cost-effectiveness analysis included the monthly customer charge. Additionally, the question appears to be related to annual operational costs and not lifetime cost-effectiveness, which was the basis for the Company's analysis. Annual operational costs do not include upfront capital costs which are an important factor when assessing consumer energy solution decisions.

b) Regarding the model results displayed in the Guidehouse memo, the energy cost data provided by Enbridge Gas to Guidehouse included tax for electricity and did not include tax for natural gas. However, as described above, Enbridge Gas did not rely on the model inputs/outputs used by Guidehouse within its memo. Rather, the Company used the model in conjunction with more precise model inputs to establish its analysis/conclusions.

Regarding Enbridge Gas's lifetime cost-effectiveness analysis/conclusions, the energy cost data used did not include tax for natural gas or electricity.

[5] Ibid.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 175

For the table in JT1.19 at page 326: (1) to add two rows to the table for figures for blue and green hydrogen in the common value of dollars per kilogram; (2) to add a column for the cumulative amount of each kind of hydrogen in the diversified scenario; (3) add some additional clarifying descriptors to the table.

Response:

The following response was provided by Guidehouse Canada Ltd.:

The following information has been added to Table 1 from Exhibit JT1.19. The Pathways to Net Zero (P2NZ) model values for domestic production of green and blue hydrogen presented in this undertaking are after-the-fact ad hoc transformations of interim model outputs calculated based on the production cost (CAPEX and OPEX) and the production volume of each type of hydrogen. Caution should be used in interpreting them or comparing them to other industry values. As discussed at TC Tr. Vol 1 178 to 182, these values are not direct outputs of Guidehouse's analysis and may not align with other industry values, given methodology differences; thus, these values likely have limited usefulness in comparison with other sources for such costs. Please note the following caveats:

1) Cost estimates for the P2NZ Study were developed to inform a "total price tag" comparison of two net-zero scenarios.
2) Costs presented here do include cost of feedstock (methane for blue hydrogen, electricity for green hydrogen), cost of equipment, and cost of emissions (for blue hydrogen).
3) Costs presented here do not include the cost of financing, taxes, profits, ROE, etc. As such, these figures are not comparable to commodity costs, market prices, or customer rates.

Table 1

Type of Value	Reference	Fuel Description	2020 $/kg (real 2020$CAD)	2030 $/kg (real 2020$CAD)	2040 $/kg (real 2020$CAD)	2050 $/kg (real 2020$CAD)	Cumulative Supply / Production from P2NZ Model (million kgs) (2020-2050)
P2NZ[3]	KT1.3, page 4	Hydrogen Imports from Quebec		2.0	1.6	1.5	44
	KT1.3, page 4	Hydrogen Imports from Western Canada		2.4	2.1	1.8	142
		Ontario Green Hydrogen (Diversified Scenario)[4]	N/A	N/A	2.14	2.00	1,943
		Ontario Blue Hydrogen (Diversified Scenario)[5]	N/A	1.64	0.88	0.64	3,998
Estimate, EB-2019-0294, Exhibit I.ED.6	Exhibit I.4.2-ED-131	Estimated production cost of Hydrogen from P2G in Ontario	6.24 to 7.80[6]	4.37 to 5.46[7]			
	Exhibit I.4.2-ED-131	Retail Hydrogen price in Ontario	8.23 to 8.87[8]				
	Exhibit I.4.2-ED-131	Retail hydrogen price in California	16.01 to 21.11[9]				
	Exhibit I.4.2-ED-131	Retail hydrogen price in Quebec	18.04[10]				

/u

[3] All model values converted using a lower heating value of 119.88 MJ/kg. The model values are derived from the values provided at exhibit JT9.22 and Exhibit JT9.22 Attachment 1.
[4] Derived from Model Output: This is the derived supply cost that best represents a proxy for commodity cost. Annual electrolyzer costs (average annual CAPEX by decade and annual O&M) plus cost of electricity needed, divided by annual hydrogen production via electrolyzers.
[5] Derived from Model Output: This is the derived supply cost that best represents a proxy for commodity cost. Annual SMR costs (average annual CAPEX by decade and annual O&M) divided by annual hydrogen production via SMR.
[6] Based on assumptions as specified in EB-2019-0294, Exhibit 1.ED.6 (g) and converted to kg using a higher heating value of 141.88 MJ/kg.
[7] Assumed a net reduction of 30%, as specified in EB-2019-0294 (h), and converted to kg using a higher heating value of 141.88 MJ/kg.
[8] Based on information provided in EB-2019-0294, Exhibit 1.ED.6 (l), and converted to kg using a higher heating value of 141.88 MJ/kg.
[9] Based on information provided in EB-2019-0294, Exhibit 1.ED.6 (k) and converted to kg using a higher heating value of 141.88 MJ/kg.
[10] Based on information provided in EB-2019-0294, Exhibit 1.ED.6 (m) and converted to kg using a higher heating value of 141.88 MJ/kg.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 183

(1) to provide a time estimate for post-outage checks in individual homes; (b) for the three most recent significant or substantial outages, to provide information including total customers impacted, the cost to do in-home checks.

Response:

Table 1 presents the data for the latest three significant outages that resulted in post-outage checks in individual properties.

Table 1

Line No.	Date	# of Customers	Cost
		(a)	(b)
1	6/11/2023	101	$15,085
2	6/5/2023	104	$11,031
3	5/8/2023	118	$18,025

The costs shown include turning off the gas, remaining on-site for damage to be repaired and completing the service relight. Reasonable time expectancy for post-outage checks is 60 minutes per property.

The above costs and duration are reflective of unplanned outages and should not be used to infer the cost or time requirements for a planned activity. The work required for converting a pipeline network (such as a transition from natural gas to 100% hydrogen) would be a planned and coordinated effort that would include optimized scheduling, advanced customer communications and dedicated resources.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 186

To indicate the number of homes that Enbridge has had to go into for reintroducing gas over the last three years and, to the extent the information is available, to break that down between outages, new connections, meter exchanges, and anything else, on a best-efforts basis.

Response:

The following chart presents the estimated[1] number of instances that Enbridge Gas has entered properties over the last three years for the purposes mentioned:

Table 1
Estimated Number of Properties Entered

Category/Year	**2020**	**2021**	**2022**
Unplanned Service Interruptions	65,562	71,748	91,453
Planned Service Interruptions	25,135	33,545	45,168
Meter Exchanges / Meter Work	148,729	129,026	160,981
Connections / Inspections	69,478	57,041	44,375
Total	**308,904**	**291,360**	**341,977**

Entry into customer properties is a standard day-to-day activity for Enbridge Gas that is enabled by established policies, procedures, business processes and operator qualifications.

[1] Data provided are estimates due to historically different coding and system requirements between the two legacy utilities.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 191

To confirm a hydrogen blending range of between 5 to 20 percent

Response:

Confirmed. A hydrogen blend of between 5% and 20% by volume (1.6% to 7.3% by energy)[1] is the expected blending range over the near term. This range may expand over time as Enbridge Gas assesses its system's capabilities to accept more hydrogen.

The percentages of energy content will vary depending on the energy content of the natural gas and the hydrogen. The following values are based on heating values in footnote 1. /u

In EB-2019-0294 Exhibit I.ED-12, page 15, the approximate 6% is the percentage of the energy content provided in a 20% by volume hydrogen blend when not accounting for the increased volume of blended gas to deliver the same energy content. The 7.3% in the response above is the percentage of energy content provided by hydrogen in a 20% by volume hydrogen blend when accounting for the increased volume of blended gas to achieve the same energy content as 100% natural gas. /u

A 5% by volume of hydrogen equates to 1.6% energy content of the blended gas, whether or not the increased volume of blended gas is considered. The relationship diverges beyond 5% by volume hydrogen, as seen in Table 1. /u

[1] Based on a hydrogen high heating value of 12.1 MJ/m^3 and a natural gas high heating value of 38.8 MJ/m^3.

/u

Table 1
Difference in Energy Content of Hydrogen With/Without Increased Volume

Line No.	% H2 (by volume)	Energy content without considering increased blended gas volume	Energy content with considering increased blended gas volume
		(a)	(b)
1	0	0.0%	0.0%
2	2	0.6%	0.6%
3	5	1.6%	1.6%
4	10	3.1%	3.4%
5	20	6.2%	7.3%

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 68

To provide Enbridge's understanding of what has driven the difference between the reference case we see here and reference case which underlies the capital plan.

Response:

Prior to the undertaking being taken, there was a great deal of discussion about Posterity's annual volume forecast analysis as highlighted in Exhibit K3.2, page 20 as compared to Enbridge Gas's current annual volume forecast as highlighted in Exhibit K3.2, page 18 (see Tr. Vol. 3 61 to 68).

Enbridge Gas would like to clarify a response given by Ms. Wade at Tr. Vol. 3 60 lines 22 to 23, where she confirms, subject-to-check, that the load forecast that is the basis of the capital plan is higher for every year of the rebasing period than the reference case. This is confirmed for the annual volume forecast, as was being discussed just prior to this statement; however, Enbridge Gas wishes to clarify that this annual volume forecast is not the basis of the capital plan, as Ms. Wade notes at TR. Vol. 3 69 lines 12 to14.

Enbridge Gas's distribution design hour demand forecast, which underpins the capital plan, used the same reference case trends as those underpinning the Posterity analysis. These trends were applied to updated demands based on growth in customers, resulting in a different total design hour demand. Exhibit 1, Tab 10, Schedule 4, paragraph 26 to 32 explains what and how aspects of energy transition have been accounted for. Exhibit I.1.10-SEC-23 provides an updated figure showing the impacts on total system design hour demand from applying the Posterity reference case trends on a per customer basis. Posterity's reference case peak hour demand forecast is found at Exhibit I.1.10 SEC-31, Attachment 1 page 34. Comparing Posterity's reference case peak hour demand forecast to Enbridge Gas's distribution design hour forecast underpinning the capital plan shows that Enbridge Gas's design hour demand forecast is lower for every year of the rebasing period than Posterity's reference case peak hour demand forecast for the same time period. For example, in 2028 the difference is greater than 400,000m^3/hour.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 77

To make best efforts to advise within 2022 how much of that hypothetical executive's incentive pay came from the EBITDA generated by growth capital line.

Response:

The short-term incentive pay generated from EBITDA Generated by Growth Capital metric would have been $14,000 using a hypothetical executive salary of $350,000 for 2022. This metric is not associated with the long-term incentive plan.

/u

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 84

Referring to exhibit KT9.2, to provide a comparable number for hydrogen as a percentage of energy mix.

Response:

The response provided at Tr. Vol. 3 85 to 86 was incorrect with respect to the percentage of total energy demand in 2050 for hydrogen in the diversified scenario and in the electrification scenario. The correct percentages are 39% for the diversified scenario and 13% for the electrification scenario.

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking

Tr: 192

To file electrification and energy transition panel's submission to the OEB's framework for energy innovation.

Response:

Enbridge Gas understands that Ms. Girvan of Consumers Council of Canada's request is different than the undertaking captured in the transcript, which is shown above. Enbridge Gas understands that Ms. Girvan requested Enbridge Gas's submission to the Ontario Energy Board (OEB) related to the OEB's submission to the province's Electrification and Energy Transition Panel, which is provided at Attachment 1.

Introduction

Enbridge Gas Inc. (Enbridge) appreciates the opportunity to submit feedback on the Ontario Energy Board's (OEB) Regulatory Framework Workshop held on April 19, 2023. Below are the consultation questions with Enbridge's responses and recommendations.

Workshop Questions

1. Long Term Planning

What role should the OEB play in long-term planning?

What is required to ensure coordination or oversight of planning is clear and predictable while also nimble and responsive?

OEB's current role is to provide regulation of the energy sector. The OEB provides expertise and value in facilitation between the stakeholders in the energy sector. Enbridge expects that OEB's strength in facilitation would be well suited and could be leveraged in the oversight of regional energy system planning for the electric and gas sectors. The OEB is the logical entity to provide facilitation of long-term planning, given they already regulate all of the parties. Enbridge recommends the OEB be tasked with facilitating long-term planning over the creation of a new central agency or authority. Enbridge also suggests that the OEB should lead a periodic consultative process on energy transition. Based on a recommendation by the OEB, Enbridge would be pleased to work with the Independent Electricity System Operator (IESO) and local distribution companies (LDCs) on coordinated regional energy system plans.

The discussion guide provides several illustrative examples of the potential roles the OEB could play in long term energy planning. Enbridge provides comments on each example below.

Set expectations for development of coordinated planning document:

Enbridge agrees that this is an appropriate role for the OEB in long-term energy system planning. Enbridge is a vertically integrated company and serves as the system operator, system planner and local transmitter and distributer of natural gas. On the electric side, Enbridge understands that vertically integrated planning has commenced via IESO's integrated planning; however, it is focused solely on transmission, and distribution system planning is done separately by LDCs. Enbridge suggests that horizontal planning be done at the regional level, looking at distribution system planning which then gets incorporated at the transmission and storage level.

Enbridge surmises that more coordination between electricity LDCs, Enbridge and regional municipalities early in system planning would help to enhance stakeholder participation, identify energy system constraints, and provide opportunities for more coordinated solutions and system development.

Under an OEB-established set of guiding principles, energy system planners could create asset management plans and/or plans for specific projects that would ensure better infrastructure investments for both electric and gas systems. For rebasing applications and Leave-to-Construct (LTC) applications, the OEB may consider establishing requirements for consultation and coordination between the local system planners to ensure that best available information is considered when putting forward a LTC for approval.

As an economic regulator, there should be a requirement to determine and quantify reliability and resiliency in the long-term plans being brought forward to OEB for approval. Enbridge is aware that OEB is pursuing greater clarity on how to define, analyze and enhance policy related resiliency for electricity distribution, as summarized in EB-2023-003. Enbridge suggests that a holistic approach to energy system resiliency be considered for Ontario. This would further enable and encourage coordinated planning on all

levels (i.e., distribution, transmission, and storage) between electric and gas system planners and ensure that the most cost-effective and resilient energy system is constructed and ready to serve Ontario. This would allow OEB to review and approve strategic infrastructure investments as energy transition continues to unfold and as climate events become more unpredictable.

Review assumptions, inputs or processes related to coordinated planning:

Enbridge suggests that basic elements of planning should include understanding system capabilities on both gas and electric systems, both in terms of annual, seasonal and peak demand, and the reliability and resiliency of each system under varying conditions as Ontario contemplates a changing energy system. The OEB could collect this information from the gas and electric system planners using common units (such as $/MW) to allow greater comparison between energy systems. This would ensure alignment of short, medium and longer term demand forecasts and the identification of any co-dependencies across energy systems and throughout the value chain (production, transmission, distribution and end-user energy consumption).

Provide recommendations to IESO or government for consideration in finalizing a coordinated planning document:

Enbridge supports the idea of the OEB providing recommendations to IESO, Enbridge and the LDCs on a coordinated plan. This should include outlining areas of agreement or differences in the areas mentioned above.

Decide rates and facilities applications in the context of coordinated planning outcomes:

Enbridge agrees that rates and facilities applications should consider coordinated planning outcomes and that the OEB should include this in deciding these applications. Further discussion on leave to construct approvals are provided in section 3.

2. Objectives

Should the OEB's statutory objectives be amended to reflect the energy transition, net zero, or other priorities?

Are there any existing objectives that may need to be revisited in the context of the energy transition?

Enbridge agrees that the Ontario Energy Board Act, 1998, S.O. 1998, CHAPTER 15, Schedule B should be amended to reflect energy transition on the evolving energy sector in Ontario.

OEB is an economic regulator that is mandated to ensure fairness, minimize cost and risk to consumers. Enbridge believes that OEB can fulfil its role as an economic regulator as well as consider public policies. In addition to ensuring energy remains affordable, the OEB should also consider energy transition, as well as ensuring energy system reliability, resiliency and innovation. Enbridge notes that any update to objectives should not be based on net zero or electrification in advance of the government determining the approach the province will take in energy transition. Until the government has determined what greenhouse gas (GHG) reduction targets will be set beyond 2040 and which pathway is most appropriate to achieve them, the OEBs objectives should focus on enabling the development of "safe bet" or "no-regret" actions, which have been identified by Enbridge and IESO. This includes new technologies, low- and zero-carbon fuels such as renewable natural gas (RNG) and hydrogen, and carbon capture, use and storage (CCUS). Enbridge suggests that the statutory objectives for 'gas' be updated to include "to facilitate innovation in the gas sector", consistent with the statutory objectives of the electricity sector. Energy transition presents a unique opportunity for the energy sector to modernize and to innovate, and this should be encouraged for both the electricity and gas sectors. Technologies and use of RNG and

hydrogen are good examples of how innovation could be further promoted to reduce GHG emissions within the gas industry, while ensuring economic benefits to protect the interests of consumers and deliver public value of a safe, reliable and resilient energy system.

3. Leave to Construct (Facilities) Approvals

Would it be beneficial to include, for example, net zero considerations in OEB decision-making authorities related to LTC?

What considerations should the OEB take into account when making decisions related to LTC?

Enbridge suggests that OEB consider a holistic approach to LTC review and approval when it comes to energy transition considerations. A holistic approach could consist of, but is not limited to, reviewing key project considerations such as safety, reliability, and resiliency of energy systems in balance with short- and long-term energy needs while also ensuring future optionality for further GHG emission reductions.

As OEB is aware, there are currently many energy sources available to customer homes and businesses, and each customer has unique needs and constraints. Enbridge suggests OEB consider customer needs and customer energy choice in balance with GHG emission reduction in LTC applications.

In order to consider energy transition in an LTC, a benefit-cost analysis method that is consistent across both electric and gas sectors should be used to ensure that the most cost-effective energy solution is selected. This benefit-cost analysis should include avoided energy generation/use and avoided GHG emissions. Further, overall costs to customers should be considered (i.e., all costs for a customer to electrify and/or change equipment) and not just operational costs. This benefit-cost analysis would likely be more comprehensive and accurate if based on discussions/findings obtained via coordinated planning efforts between Enbridge, the local distribution company (LDC) and municipalities.

It is important that the value and cost of reliability and resiliency, emissions/carbon charges, infrastructure required to deliver the energy (generation, transmission, and distribution) on both systems are quantified and considered. A holistic approach to energy system planning is needed to ensure that the most optimal path for the least cost is selected. Above all, it is paramount that short term energy needs are reviewed in balance with GHG emission reductions, and cost are considered with long term energy considerations and pathway to net zero optionality is maintained. Otherwise, there could be long term unintended consequences (likely financial) for the residents of Ontario.

4. Electricity Distribution Activities

Does s. 71 provide the right balance between customer protection and the services that LDCs need to provide in 2023 and beyond?

Does the broader question of the role of LDCs need to be considered?

How can the OEB ensure that consumers are protected as distribution activities evolve?

Should the OEB be given the authority to grant generic exemptions (rather than only on a case-by-case basis) for certain types of activities?

Consistent with Enbridge's comments above related to coordinated planning, Enbridge suggests that coordinated planning between gas distributors and electric distributors should be completed and documented as part of LTCs. This would ensure that energy system infrastructure investments are made prudently.

5. Indigenous Relationships

What should be the OEB's role in ensuring that Indigenous perspectives are considered in the energy transition?

What engagement or outreach processes would be most effective?

Enbridge regularly engages with approximately 40 Indigenous groups in Ontario and is committed to fostering long-term meaningful relationships based on our Life Cycle approach to engagement. Life Cycle approach to engagement refers to engaging with potentially affected Indigenous groups from a project's infancy/project planning stage through to decommissioning/abandonment.

Enbridge suggests that Indigenous engagement and/or outreach in relation to energy transition be completed for matters that are OEB policy and/or governance related. The duty to consult for specific projects and/or operations should remain with the project proponent. This would ensure that efforts are not duplicated for specific projects, which could overburden Indigenous communities with additional and unnecessary stakeholdering efforts and/or create miscommunication within the sector. Enbridge suggests that all Indigenous engagement efforts continue to be documented and provided to OEB to ensure that a sufficient level of consultation has been completed and that it satisfies OEB's expectation regarding Indigenous engagement.

6. Innovation

Is there a need for additional support for innovation in the energy sector?

Would legislative change be desirable to give the OEB more tools to support innovation for the benefit of consumers?

Energy transition provides an unprecedented opportunity for the energy sector provincially, nationally and internationally to explore innovative solutions to address GHG emission reductions. Enbridge recommends that innovation be promoted equally across all energy sectors - electric and gas - to drive industry to explore novel and nascent technologies and see them through to commercialization within a faster pace.

As noted above, an expansion of the statutory objectives for 'gas' to include innovation and an update to the definition of 'gas' are needed to create the regulation framework for these changes.

As OEB is aware, there is a mature natural gas market today where prices of natural gas correspond to market conditions. Enbridge procures natural gas to meet customer demands cost effectively due to the underground storage capabilities. As low-carbon fuels are brought into the energy supply mix to reduce emissions, one of the key challenges is limited supply and high costs. Fuels such RNG are currently priced so that project developers can recover their costs. Technology innovation to maximize supply and lower costs is necessary to make low-carbon fuels accessible and affordable for customers.

For high-temperature industrial applications and heavy-duty transportation where electrification is not feasible, carbon capture, utilization and storage (carbon capture and sequestration (CCUS)) can help effectively lower GHG emissions. However, customers are faced with high upfront investment in CCUS, and those located far from storage sites lack utilization options. Financial incentives and/or funding will help foster exploration of CCUS technologies to become more modular and scalable based on customer needs and drive technology advancement on a commercial scale.

Conclusion

Enbridge appreciates the opportunity to provide feedback and recommendations on the OEB's Regulatory Framework Workshop held on April 19, 2023. Enbridge requests consideration of the recommendations identified in this document and welcomes the opportunity to meet with you to discuss the consultation and recommendations in further detail. If you have any questions or require additional information, please do not hesitate to contact Cara-Lynne Wade at cara-lynne.wade@enbridge.com.

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 16

On a best-efforts basis, to file the source information related to emission factors for the RNG as shown in the Enbridge RNG presentation table at Exhibit K3.4, page 46.

Response:

The figure presented in Exhibit K3.4, page 46 obtained from the November 15, 2022, Ontario Sustainable Energy Association presentation by Enbridge Gas was originally published in a working paper by the World Resources Institute[1] and is based on information obtained in 2020 from the California Air Resource Board (CARB) Low Carbon Fuel Standard Program (Ca LCFS).

Enbridge Gas would like to note that the figure does not show emission factors, rather it presents lifecycle carbon intensity (CI) values for various fuels registered in the Ca LCFS program. It is important to note that lifecycle CI values are different from emission factors and are not interchangeable terms. The lifecycle CI represents the GHG sources or sinks that occur across the full fuel lifecycle, from the point of fuel extraction to its end-use combustion.

The term emission factor refers to emissions released from the end use combustion of a fuel and does not include greenhouse gas (GHG) sources or removals, otherwise known as sinks, from the upstream production and transportation of a fuel. The emission factor for all types of renewable natural gas (RNG) is zero, as the carbon dioxide released from the end use combustion of RNG is biogenic (i.e., carbon dioxide emissions resulting from the decomposition or destruction of organic material, including those produced from the destruction of landfill gas, which are considered to be a natural part of the carbon cycle).[2]

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[1] World Resources Institute. December 2020. Renewable Natural Gas as a Climate Strategy: Guidance for State Policy Makers. Pg. 7. https://files.wri.org/d8/s3fs-public/renewable-natural-gas-climate-strategy.pdf.

[2] Environment and Climate Change Canada. 2022. National Inventory Report 1990-2020: Greenhouse Gas Sources and sinks in Canada. Section A3.6.1 Emissions from Solid Waste Disposal (Landfills) Page 200. https://publications.gc.ca/collections/collection_2022/eccc/En81-4-2020-2-eng.pdf.

As demonstrated in the figure derived from the Ca LCFS program, the carbon intensity of RNG can vary significantly between types and individual projects, as it considers both avoided and produced emissions occurring over its lifecycle. Negative carbon intensity values for RNG can occur for projects that voluntarily capture methane that would have otherwise been released to the atmosphere. Landfill based RNG supplies often have positive carbon intensities as a result of regulations that require the collection and destruction of landfill gas (i.e., avoided methane emissions are not included in the carbon intensity calculation because it is a required activity). Where a landfill is not subject to landfill gas collection and destruction requirements and voluntarily collects landfill gas for production into RNG, the resulting carbon intensity would likely be negative due to the avoided methane emissions.

Enbridge Gas voluntarily reports Scope 3 emissions for end-use combustion only. This does not include any upstream emissions (such as from production and processing of natural gas or RNG) or any avoided upstream emissions (such as methane captured from RNG sources). Enbridge Gas uses the end-use combustion emission factors in the National Inventory Report for natural gas as specified for Ontario, which is 0.001932 tCO_2e/m^3.[3] Enbridge Gas also uses these end-use emission factors when reporting emission reductions from an RNG or hydrogen project.

[3] Environment and Climate Change Canada. (2022, April 14). 2022 National Inventory Report 1990-2020: Greenhouse Gas Sources and Sinks in Canada. Part 2. Table A6.1-1 and Table A6.1-3.

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 26

To advise as to whether the GHG reduction calculations in IR Pollution Probe 6 from EB-2022-0203 are expressed the way they are (reference: exhibit K3.4, page 48.

Response:

The estimated value of 110,000 tonnes of carbon dioxide equivalent (tCO_2e) per year expected greenhouse gas (GHG) emissions reduction presented in the Notice of Study Commencement and Virtual Information Session for the Proposed Ridge Landfill RNG Project was originally calculated and provided by the RNG producer.

Pollution Probe requested that the calculations used to determine this value be provided in the interrogatory for EB-2022-0203, Exhibit I.PP.6. Enbridge Gas provided the calculations based on the understanding of the producer's intention to potentially direct this RNG to vehicles. The estimated emissions reduction value was calculated using end-use emission factors and is meant to represent the avoidance of tailpipe emissions that will occur if those vehicles use RNG instead of gasoline.

The Proposed Ridge Landfill RNG Project Notice of Commencement and Virtual Information Session also aimed to contextualize the amount of RNG this project would produce by expressing the amount of GHG reductions in terms of "number of homes". The number of homes was determined based on the amount of RNG and the average use of natural gas per home per year. The comparison to homes did not use the emissions reductions calculation for RNG used to displace gasoline.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 130

Provide a policy or a document that speaks to Enbridge's approach to additionality in the context of RNG procurement.

Response:

Enbridge Gas does not have a policy that speaks to the Company's approach to additionality in RNG procurement.

At Tr. Vol. 4 page 127, Enbridge Gas's witness agreed that renewable natural gas (RNG) in the gas supply is only valuable as a safe bet in the context of the energy transition if it is based on the principle of additionality. Further discussion on additionality occurred between Enbridge Gas witnesses and Commissioner Moran starting at Tr. Vol. 4 page 133. Enbridge Gas would like to clarify its testimony in these exchanges.

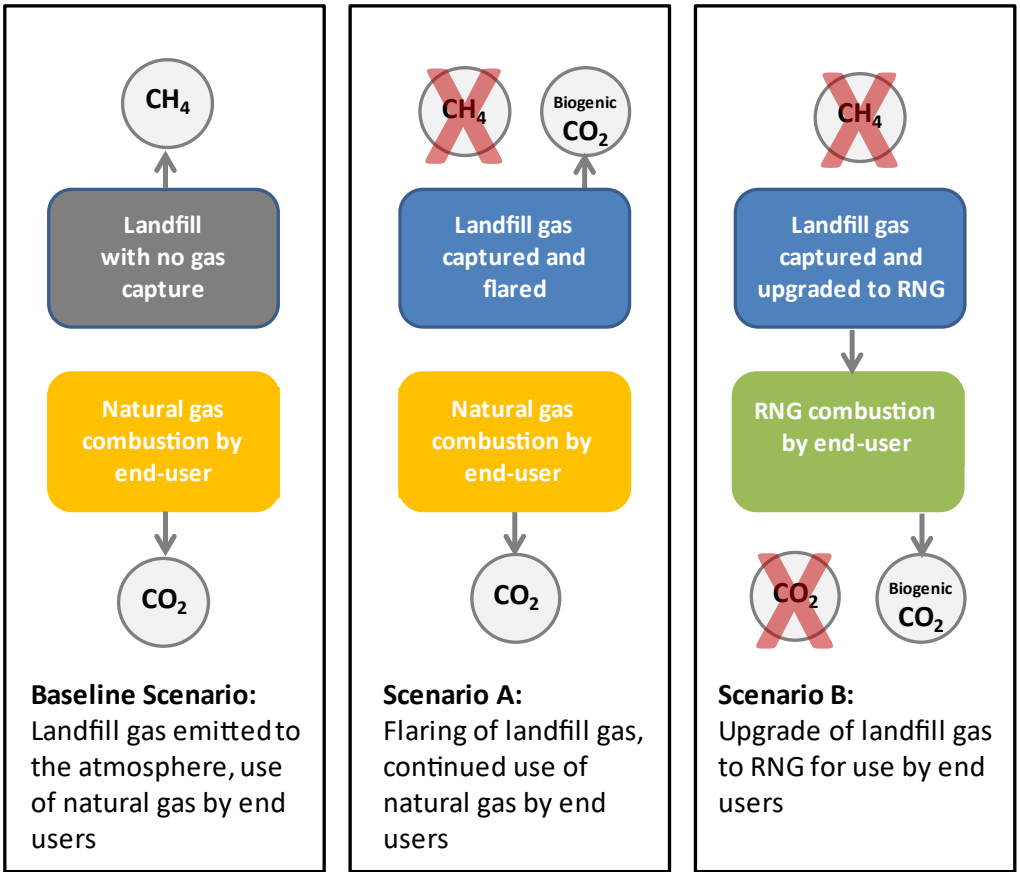
Enbridge Gas understands additionality to be defined as "a criterion for assessing whether a project has resulted in GHG emission reductions or removals in addition to what would have occurred in its absence."[1] As noted in the GHG protocol, additionality "is an important criterion when the goal of the project is to offset emissions elsewhere".[2] The replacement of natural gas with RNG in the gas distribution system is not considered, and is different than, an offset; it is a direct reduction of an end-user's Scope 1 GHG emissions, which would be considered as a Scope 3 GHG reduction for Enbridge Gas. Enbridge Gas, therefore, does not agree with Mr. Millar that additionality should be considered when procuring RNG for injection into the natural gas supply.

To provide further clarity on when additionality is and is not considered, Enbridge Gas is providing additional context around the two separate and distinct GHG benefits that can be realized when landfill gas is captured and used as a source to create RNG. As shown in Figure 1, the two GHG benefits that occur are:

[1] World Resources Institute. "The Greenhouse Gas Protocol". 2005, pg. 96. https://ghgprotocol.org/sites/default/files/standards/ghg-protocol-revised.pdf
[2] Ibid

1. Avoided release of methane to the atmosphere
2. Avoided carbon dioxide emissions from the displacement of natural gas.

Figure 1 – Double Benefit from the Creation and Use of RNG



Benefit 1 – Avoided Release of Methane to the Atmosphere

Capturing landfill gas, which is predominantly methane, and destroying it through combustion instead of allowing it to be released to the atmosphere provides the first GHG benefit. This GHG benefit occurs whether the landfill gas is flared or used to generate useful energy such as electricity or RNG. Offset credits can be created for the amount of GHG emissions savings related to the avoided methane emissions, where applicable offset regulations or voluntary offset programs exist. For example, as discussed at Tr. Vol. 4136, the federal GHG Offset Regulations[3] allow for the creation of offset credits from landfill gas projects under the Landfill Methane Recovery and Destruction Protocol (Landfill Destruction Protocol). Projects creating offset credits under this protocol must demonstrate that the landfill is not required by law to capture

[3] Government of Canada. (2022, May 20). Canadian Greenhouse Gas Offset Credit System Regulations, SOR/2022-111. https://gazette.gc.ca/rp-pr/p2/2022/2022-06-08/html/sor-dors111-eng.html

and destroy the landfill gas, which is a requirement in the protocol to ensure additionality.

Enbridge Gas does consider additionality in the procurement of offset credits. For example, when Enbridge Gas procured offset credits for use as a compliance instrument under Ontario's Cap and Trade Program and the federal Output-Based Pricing System, the Company only procured offset credits that were considered additional as demonstrated by third-party verification, as required under the applicable regulations.

Benefit 2 – Avoided CO_2 Emissions from the Displacement of Natural Gas

When landfill gas is captured, cleaned and injected into the gas distribution system as RNG, a second GHG benefit is realized. Each cubic meter of RNG displaces a cubic meter of natural gas, and the associated amount of carbon dioxide that is released to the environment from natural gas combustion is avoided. Because the carbon dioxide released from the combustion of RNG is biogenic[4] (i.e., carbon dioxide emissions resulting from the decomposition or destruction of organic material, including those produced from the destruction of landfill gas, which are considered to be a natural part of the carbon cycle) no net additional carbon dioxide is created. Where the landfill gas is flared instead of upgraded to RNG, this second benefit would be a lost opportunity for emissions reductions as natural gas would have been combusted by the end-user instead.

The displacement of natural gas with RNG provides savings from carbon pricing for homeowners and business in Ontario as the carbon dioxide emissions from the combustion of RNG are exempt from both the Federal Carbon Charge under the Greenhouse Gas Pollution Pricing Act[5] (GGPPA) and the Ontario Emissions Performance Standards[6] [7] (EPS). Neither the GGPPA or EPS require the RNG to meet any additionality requirements to recognize the GHG reductions and avoided costs.

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[4] Environment and Climate Change Canada. 2022. National Inventory Report 1990-2020: Greenhouse Gas Sources and sinks in Canada. Section A3.6.1 Emissions from Solid Waste Disposal (Landfills) Page 200. https://publications.gc.ca/collections/collection_2022/eccc/En81-4-2020-2-eng.pdf

[5] Greenhouse Gas Pollution Pricing Act, S.C. 2018, c.12, s.186. Section 8, subsection 7; Natural gas that contains biomethane. https://laws-lois.justice.gc.ca/eng/acts/G-11.55/FullText.html

[6] O. Reg. 241/19: Greenhouse gas emissions performance standards. https://www.ontario.ca/laws/regulation/190241#BK21 references the verification amount set out in the report prepared under the O. Reg 390/18

[7] O. Reg 391/18: Greenhouse gas emissions: quantification, reporting and verification. Section 12, subsection 2.

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 11

Enbridge will advise as to whether the maximum rebate is available to customers who are transitioning away from gas; and will advise to whether and/or how its marketing or program materials make that clear; and will advise as to whether any change has been made in the underlying agreement between Enbridge Gas and Enercan, to reflect the availability of the maximum rebate or incentive for customers who are switching away from gas.

Response:

Enbridge Gas can confirm that it has modified the HER+ eligibility requirements consistent with the OEB Decision in EB-2021-0002 (DSM Plan proceeding).[1] This includes modification of the marketing and implementation materials used during training/roll out for the Service Organizations that perform the D and E audits (as defined in the excerpts below). The contract with NRCan has not been amended as none of the contractual terms in that agreement stipulate eligibility requirements or funding caps based on Enbridge Gas funding, so there are no items to amend. The Company can confirm that Enbridge Gas has clearly communicated the OEB Decision and implications for HER+ to NRCan and that, to the best of Enbridge Gas's knowledge, Service Organizations are aware of the HER+ program requirements.

The following is an excerpt from the Service Organization training/rollout communications and serves to demonstrate the HER+ eligibility requirements:

> "In order to be eligible for the enhanced Enbridge incentives participants must have Enbridge natural gas space heating at the time for the pre-retrofit energy assessment (the "D Audit") ***and/or*** the post-retrofit energy assessment (the "E Audit")." [***Emphasis added***]

There are three specific use cases encompassed in the language which are intended to broadly define a gas customer to be consistent with the OEB DSM Plan Decision and

[1] In Exhibit K7.2, page 5, Pollution Probe provided an excerpt from a November 24, 2022 filing of unredacted materials that were created prior to the OEB's EB-2021-0002 Decision. This excerpt was not part of the legal agreement and was not updated after the OEB decision, and therefore contains the pre-decision eligibility criteria.

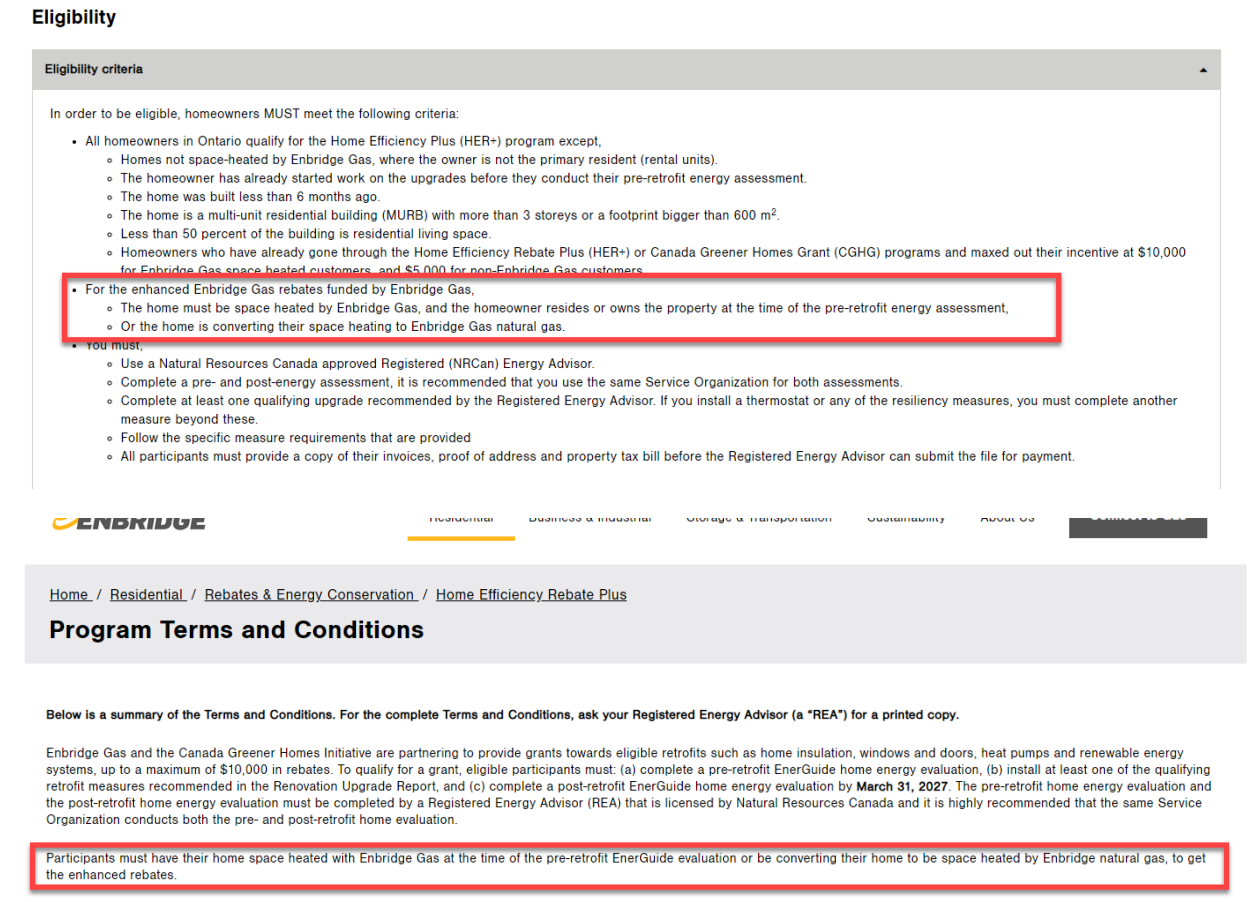
/u

any of the following cases are eligible for the enhanced measure rebates and increased funding cap of $10,000.

1) At the time of "D" **and** "E" – Gas customer both before and after the audits
2) At the time of "E" **only** – New gas customer attaching to the gas system
3) At the time of "D" **only** – Existing gas customer detaching from the gas system

Additional information/FAQ on the HER+ program, including eligibility requirements, can be found at: https://www.enbridgegas.com/residential/rebates-energy-conservation/home-efficiency-rebate-plus/faq

The Company has also provided selected images of the marketing material below describing the program eligibility as requested.



Eligibility

Eligibility criteria

In order to be eligible, homeowners MUST meet the following criteria:

- All homeowners in Ontario qualify for the Home Efficiency Plus (HER+) program except,
  - Homes not space-heated by Enbridge Gas, where the owner is not the primary resident (rental units).
  - The homeowner has already started work on the upgrades before they conduct their pre-retrofit energy assessment.
  - The home was built less than 6 months ago.
  - The home is a multi-unit residential building (MURB) with more than 3 storeys or a footprint bigger than 600 m^2.
  - Less than 50 percent of the building is residential living space.
  - Homeowners who have already gone through the Home Efficiency Rebate Plus (HER+) or Canada Greener Homes Grant (CGHG) programs and maxed out their incentive at $10,000 for Enbridge Gas space heated customers, and $5,000 for non-Enbridge Gas customers.
- For the enhanced Enbridge Gas rebates funded by Enbridge Gas,
  - The home must be space heated by Enbridge Gas, and the homeowner resides or owns the property at the time of the pre-retrofit energy assessment,
  - Or the home is converting their space heating to Enbridge Gas natural gas.
- You must,
  - Use a Natural Resources Canada approved Registered (NRCan) Energy Advisor.
  - Complete a pre- and post-energy assessment, it is recommended that you use the same Service Organization for both assessments.
  - Complete at least one qualifying upgrade recommended by the Registered Energy Advisor. If you install a thermostat or any of the resiliency measures, you must complete another measure beyond these.
  - Follow the specific measure requirements that are provided
  - All participants must provide a copy of their invoices, proof of address and property tax bill before the Registered Energy Advisor can submit the file for payment.

Home / Residential / Rebates & Energy Conservation / Home Efficiency Rebate Plus

Program Terms and Conditions

Below is a summary of the Terms and Conditions. For the complete Terms and Conditions, ask your Registered Energy Advisor (a "REA") for a printed copy.

Enbridge Gas and the Canada Greener Homes Initiative are partnering to provide grants towards eligible retrofits such as home insulation, windows and doors, heat pumps and renewable energy systems, up to a maximum of $10,000 in rebates. To qualify for a grant, eligible participants must: (a) complete a pre-retrofit EnerGuide home energy evaluation, (b) install at least one of the qualifying retrofit measures recommended in the Renovation Upgrade Report, and (c) complete a post-retrofit EnerGuide home energy evaluation by **March 31, 2027**. The pre-retrofit home energy evaluation and the post-retrofit home energy evaluation must be completed by a Registered Energy Advisor (REA) that is licensed by Natural Resources Canada and it is highly recommended that the same Service Organization conducts both the pre- and post-retrofit home evaluation.

Participants must have their home space heated with Enbridge Gas at the time of the pre-retrofit EnerGuide evaluation or be converting their home to be space heated by Enbridge natural gas, to get the enhanced rebates.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 73

Enbridge to file information related to capacity bids and awards for offer completed after 4 p.m. on July 25, 2023; to include relating to Enbridge's own in-franchise customers; to include information as to the length of the contract that Enbridge Gas gas supply bid into the open season.

Response:

Please see Exhibit J7.9 for the bid information and bid documents.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 80

Enbridge to advise whether since 2013 the capacity that has been bid into reverse open season bids is enough to not require any builds that Enbridge otherwise would have expected.

Response:

Bids received in reverse open seasons since 2013 have not been sufficient enough to eliminate the need for the new facilities.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 136

To confirm, if the Board had rebased Union's costs at the end of 2018, the surplus capacity costs of 210 TJs be allocated in the five categories of ex-franchise, Union South, Union North, Enbridge rate zone, and the PDO.

Response:

Please see Table 1 for the allocation of the 210 TJ/d Dawn Parkway System surplus from Union's 2013 cost of service. The allocation is in proportion to the distance weighted design day demands on the Dawn Parkway System for Winter 2018/2019, consistent with the demands provided at Exhibit I.4.7-FRPO-169, Attachment 1, line 6, column (f).

Table 1

Allocation of 210 TJ/d Surplus Dawn Parkway System Capacity from 2013 Cost of Service
Using Dawn Parkway Transmission Allocation for Winter 2018/2019

Line No.	Particulars	Commodity Kilometres (1) (10^6m^6 x km) (a)	Commodity Kilometres (1) % (b)	Allocation of 210 TJ (2) (TJ) (c)
1	Union South rate zone	8,145	20.8%	44
2	Union South rate zone - PDO (3)	(1,307)	(3.3%)	(7)
3	Union North rate zone	2,548	6.5%	14
4	EGD rate zone	17,503	44.7%	94
5	Ex-franchise	12,274	31.3%	66
6	Total	39,164	100.0%	210

Notes:
(1) Distance weighted design day demands based on the Winter 2018/2019 budget.
(2) Allocated in proportion to column (b).
(3) Union South in-franchise customers receive a distance credit as a result of the PDO, which recognizes that the design day demands supplied from Parkway are transported over a shorter distance than design day demands supplied from Dawn.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 148

To provide a full description of line 4, which is other Dawn-to-Parkway System capacity changes, which results in the total in line 3 being reduced by that amount for the total forecasted Dawn-to-Parkway system capacity in line 5.

Response:

The Dawn Parkway System capacity is derived as the design day demands plus the capacity surplus or shortfall. The capacity represents the demands that can be served by the system and does not represent the demands that are able to move from Dawn to Parkway. The capacity is not static, and changes based on the specific location of demands on the Dawn Parkway System (e.g. Union South in-franchise demands, Dawn to Kirkwall, Kirkwall to Parkway or Dawn to Parkway). The capacity recognizes that gas moving further from Dawn to Parkway uses more system capacity. For example, a demand in London and a demand in Milton are each equal to one design day demand but the demand in London will have less impact on system capacity surplus or shortfall than demand in Milton, as demand in Milton travels further from Dawn on the Dawn Parkway System. For this reason, if Dawn to Kirkwall turnback is repurposed to provide Dawn to Parkway service, the amount of Dawn Parkway System capacity will decrease.

Table 1 provides the detail for the 222 TJ/d decrease of other Dawn Parkway System capacity changes for the Winter of 2015/2016 as provided at Exhibit I.4.7-FRPO-169, Attachment 1, column (c) and as discussed in Tr. Vol 7. Other years have similar changes in these categories based on both in-franchise and ex-franchise demand changes, PDO (Parkway Delivery Obligation) changes, modelling changes and heat value of gas changes.

Table 1
Winter 2015/2016 Details of Other Dawn Parkway System Capacity Changes in Line 4

Line No.	Other Dawn Parkway System Capacity Changes	(TJ/d)
1	South and North In-Franchise Demand	85
2	Ex-franchise Demand	(153)
3	PDO	(155)
4	Model	(57)
5	Heat Value	58
6	Total (1)	(222)

Note:
(1) The decrease in capacity of 222 TJ/d for the Winter 2015/2016 is relative to the forecast capacity from Union's 2013 Cost of Service (EB-2011-2010).

These changes include:

- 85 TJ/d of incremental design day demand for the Union South and North rate zones.
- (153) TJ/d of ex-franchise demands due to contracting changes. The changes include impacts of: Marcellus gas region development and the corresponding turnback of Dawn to Kirkwall capacity; increase in Kirkwall to Parkway and Dawn to Parkway path shippers; long haul to short haul shifting for eastern customers and the EGD GTA project which increased demand but also shifted EGD rate zone suction gas to Parkway discharge.
- (155) TJ/d shift in Parkway delivery obligations from Parkway to Dawn and other year-to-year PDO changes.
- (57) TJ/d of changes to gas properties, model corrections as examples.
- 58 TJ/d of changes related to higher energy content gas arriving at the utility.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 164

Enbridge to confirm how many days has the Dawn-Parkway System reached peak Dawn-Parkway capacity requirements in the last five years.

Response:

The peak day demand did not reach the capacity of the Dawn Parkway System over the period from Winter 2009/2010 to Winter 2021/2022. Please see Exhibit I.2.7-ED-113, part c), Table 1, columns (i) and (iii) for the peak day demand and the capacity for each year.

ENBRIDGE GAS INC.

Answer to Undertaking from
Industrial Gas Users Association (IGUA)

Undertaking

Tr: 168

Enbridge to file its bid document, as described in undertaking J7.8.

Response:

Enbridge Gas interprets this question to be referring to Exhibit J7.4 instead of Exhibit J7.8.

The detailed results and related bid documents for a non-binding open season are confidential and considered competitive market information by both Enbridge Gas and other bidders in the open season. However, Enbridge Gas is able to provide the bid documents requested since the only bids received in the non-binding open season were from Enbridge Gas on behalf of its in-franchise customers.

Enbridge Gas submitted two non-binding bids on behalf of in-franchise customers in the Dawn to Parkway new capacity open season which closed on July 18, 2023:

1) 18,876 GJ/d for the EGD rate zone, starting as early as November 1, 2024. This capacity is intended to serve forecasted in-franchise design day growth in the Enbridge CDA. Attachment 1 is the bid form submitted by Enbridge Gas for this capacity.

2) 23,665 GJ/d for the Union South rate zone, starting November 1, 2027. Enbridge Gas bid smaller capacity amounts that align with forecasted demand for each year starting November 1, 2024, to serve growth in Dawn to Parkway system requirements for Union South in-franchise customers. Attachment 2 is the bid form submitted by Enbridge Gas for this capacity.

Enbridge Gas requires the capacity in the first bid using both the existing design day methodology and the design day methodology as outlined in the Settlement Proposal. Therefore, the first bid was not conditional upon the OEB's review of the Settlement Proposal.

The second bid was submitted with a condition precedent indicating the bid volume and timing is subject to change based on the outcome of the OEB's review of the Settlement Proposal in this proceeding. The bid amount was based on existing design day methodologies. There is no forecasted incremental Dawn to Parkway requirement for the Union South rate zone using design day methodologies outlined in the Settlement Proposal. Therefore, upon OEB approval of the Settlement Proposal, Enbridge Gas will withdraw its second bid in its entirety.

Enbridge Gas's bid forms included a 15-year term in order to be compliant with the open season bid process. However, since Enbridge Gas does not contract with itself for this capacity, the capacity is not actually subject to any term requirements. Instead, in-franchise customers are assumed to have rights to the capacity in perpetuity and Enbridge Gas would provide 24-months' notice should it wish to turn back capacity in the future.

On July 25, 2023, Enbridge Gas awarded both bids in their entirety, noting the condition precedent in the second bid.

July 18, 2023

BID FORM
Enbridge Gas Inc. New Capacity Open Season
M12 or M12X Firm Transportation Service

Please complete and submit this bid form no later than 2 p.m. ET/ 1 p.m. CT on July 18, 2023 and return via email to EnbridgeGas_STSales@enbridge.com.

Contact Information	
Corporate Name:	Enbridge Gas Inc. Operating as Enbridge Gas Distribution
Contact Person (Shipper Rep):	John Gillis
Title:	Senior Buyer
Telephone:	519-436-4657
Email Address:	John.gillis@enbridge.com
Service Parameters	
Receipt Point:	Dawn
Delivery Point:	Parkway
Term (minimum 15- year term):	15 yrs
Start Date:	November 1, 2027
End Date*:	October 31, 2042
Requested Early Start Date:	November 01, 2024
Quantity (GJ/d):	18,876 GJ/d
Conditions Precedent (if any):	

- *must be a minimum of 15 years from Nov. 1, 2027.

By participating in this Open Season, subject to Enbridge Gas's acceptance and notification of quantities allocated to shipper, shipper hereby irrevocably commits to execute the Firm M12 Transportation Contract with Enbridge Gas on the price, term and capacity as outlined above. If the above event does not occur within 60 days of delivery by Enbridge Gas of written notice to shipper, Enbridge Gas may, in its sole discretion, elect by written notice to shipper within 15 days thereafter, to terminate shipper's participation in this Open Season.

Enbridge Gas Inc.
P.O. Box 2001, 50 Keil Drive North, Chatham, ON, N7M 5M1 www.enbridgegas.com

July 18, 2023

BID FORM
Enbridge Gas Inc. New Capacity Open Season
M12 or M12X Firm Transportation Service

Please complete and submit this bid form no later than 2 p.m. ET/ 1 p.m. CT on July 18, 2023 and return via email to EnbridgeGas_STSales@enbridge.com.

Contact Information	
Corporate Name:	Enbridge Gas Inc. Operating as Union Gas
Contact Person (Shipper Rep):	John Gillis
Title:	Senior Buyer
Telephone:	519-436-4657
Email Address:	John.gillis@enbridge.com
Service Parameters	
Receipt Point:	Dawn
Delivery Point:	Parkway
Term (minimum 15- year term):	15 yrs
Start Date:	November 1, 2027
End Date*:	October 31, 2042
Requested Early Start Date:	11/01/2024: up to 3,975 GJ/d; 11/01/2025: up to 10,560 GJ/d; 11/01/2026 up to 17,125 GJ/d;
Quantity (GJ/d):	11/01/2027 - 10/31/2042 23,665 GJ/d
Conditions Precedent (if any):	Bid volume and timing is subject to the outcome of the OEB's review of the EB-2022-0200 Settlement Agreement.

- *must be a minimum of 15 years from Nov. 1, 2027.

By participating in this Open Season, subject to Enbridge Gas's acceptance and notification of quantities allocated to shipper, shipper hereby irrevocably commits to execute the Firm M12 Transportation Contract with Enbridge Gas on the price, term and capacity as outlined above. If the above event does not occur within 60 days of delivery by Enbridge Gas of written notice to shipper, Enbridge Gas may, in its sole discretion, elect by written notice to shipper within 15 days thereafter, to terminate shipper's participation in this Open Season.

Enbridge Gas Inc.
P.O. Box 2001, 50 Keil Drive North, Chatham, ON, N7M 5M1 www.enbridgegas.com

ENBRIDGE GAS INC.

Answer to Undertaking from
Industrial Gas Users Association (IGUA)

Undertaking

Tr: 84

To file the Minister of Energy's letter dated june 26, 2023 to the President of Enbridge, as well as Ms. Harradence's which preceded.

Response:

The letter to Enbridge Gas from the Minister of Energy dated June 26, 2023 is provided at Attachment 1.

The letter to the Minister of Energy from Enbridge Gas dated February 2, 2023 is provided at Attachment 2.

Ministry of Energy

Office of the Minister

77 Grenville Street, 10th Floor
Toronto ON M7A 2C1
Tel.: 416-327-6758

Ministère de l'Énergie

Bureau du ministre

77, rue Grenville, 10e étage
Toronto ON M7A 2C1
Tél. : 416-327-6758

Ontario

MC-994-2023-84

June 26, 2023

Ms Michele Harradence
President
Enbridge Gas Inc.
michele.harradence@enbridge.com

Dear Ms Harradence:

Thank you for your letter regarding governance arrangements during Ontario's energy transition. I am pleased to respond on the respective roles and responsibilities across the province's energy regulatory landscape.

Ontario has a robust and clear set of governance arrangements laid out in legislation and regulation. Under my direction, the Ministry of Energy is focused on developing electricity, natural gas, and fuel policies that maintain safe, reliable, and affordable energy supply, transmission and distribution systems across the province – ensuring we continue to power our growing economy.

The Ontario Energy Board (OEB) is a Crown agency whose powers and responsibilities are laid out in the *Ontario Energy Board Act, 1998* (OEBA) and other statutes. The OEB also has powers and responsibilities under a number of other Ontario statutes including, but not limited to, the *Electricity Act, 1998,* the *Municipal Franchises Act* and the *Statutory Powers Procedure Act*. The objectives of the OEB, as set out in sections 1, 2 and 2.1 of the OEBA, include facilitating "rational expansion of (gas) transmission and distribution systems" and "the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas."

The Independent Electricity System Operator (IESO) is responsible for directing the operation and maintaining the reliability of the IESO-controlled electricity grid in Ontario. The mandate of the IESO is embodied in Part II of the *Electricity Act, 1998,* and the regulations made under the act. It is also subject to the requirements set out in its licence issued by the OEB, and applicable provisions of the OEBA, the regulations made under the OEBA and any applicable OEB codes or orders. The objects of the IESO, as set out in section 6 of the *Electricity Act, 1998*, include "promoting the use of cleaner energy sources and technologies."

The government, as represented by me as the Minister of Energy, is responsible for the legislative, regulatory, and public policy frameworks under which the OEB and the IESO operate, while respecting the status of the OEB as an independent regulator and the IESO's statutory role as an independent market operator.

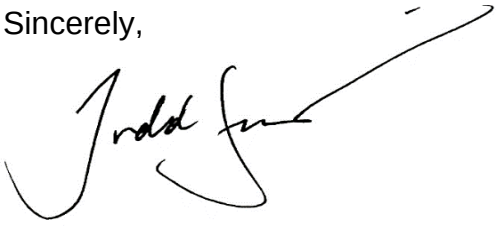
…/cont'd

As you are aware, the government has established the Electrification and Energy Transition Panel to provide strategic advice on the highest value short, medium, and long-term opportunities for the energy sector to help Ontario's economy prepare for electrification and the energy transition, including long-term, integrated energy planning. As we embark on this energy transition journey, Ontario will need to rely on its diversified energy system that serves the needs of customers safely, reliably, and affordably. It will also need to maintain a system that is economically competitive to attract investment, support industry and grow jobs. That is why, on my direction, the Ministry of Energy has commissioned an independent Cost-Effective Energy Pathways Study to better understand how Ontario's energy sector can best support electrification and the energy transition. Together, the Panel and the Pathways Study will help the government make the best strategic decisions to reform our long-term energy planning process to serve Ontarians and prepare our province for the energy system of the future.

While this work is undertaken, I am confident in the ability of the OEB and the IESO to discharge their responsibilities to the sector and the public by focusing on their respective mandates and statutory obligations and delivering outcomes that promote the interests of consumers as well as the stability and sustainability of the energy sector.

Thank you again for writing and please accept my best wishes.

Sincerely,



Todd Smith
Minister

c: Jason Fitzsimmons, Deputy Minister of Energy
Steen Hume, Assistant Deputy Minister, Energy Supply Policy Division
Karen Moore, Assistant Deputy Minister, Strategic, Network and Agency Policy Division
Susanna Zagar, Chief Executive Officer, Ontario Energy Board
Lesley Gallinger, President and CEO, Independent Electricity System Operator
David Collie, Chair, Electrification and Energy Transition Panel

Michele Harradence
President
Enbridge Gas Inc.

Enbridge Gas Inc.
500 Consumers Rd.
North York, ON M2J 1P8

February 2, 2023

The Honourable Todd Smith
Minister of Energy
10th Floor, 77 Grenville Street
Toronto, Ontario
M7A 2C1

Re. Clarifying the Governance Arrangements through Ontario's Energy Transition

Dear Minister,

On behalf of the team at Enbridge Gas Inc., we wanted to convey our excitement for the year ahead and applaud the work that your government has put in motion to help build an energy system that is clean, affordable, sustainable, reliable, and respectful of residential and business customer choice.

Many wheels have been put into motion to support electrification and energy transition in Ontario and we remain committed to supporting this work as a partner and collaborator in delivering the energy system of the future. We note the Energy Transition and Electrification Panel, established to provide the Minister of Energy with expert advice on various issues related to integrated long-term energy planning in Ontario, will launch stakeholder consultations in the weeks ahead. Esmia and Dunsky's Cost-Effective Pathways Study is underway. So too are the OEB's Innovation Taskforce consultations on the 4 D's which include electrification and moving off fossil fuels as well as the OEB's work to respond to your October 21, 2022 letter of direction. We are also eagerly anticipating consultations with the province on the "no regret decisions" recommended in the IESO's recent Pathways to Decarbonization Report.

Enbridge is committed to active engagement and supporting the province and its agencies in these undertakings. We have consistently advocated for long-term collaborative and integrated gas and electric planning to enable the most cost-effective and resilient decarbonization pathway possible for the economy as a whole. The Company also commissioned a *Pathways to Net-Zero Emissions for Ontario* report to support our strategic planning, which we have made public.

What has become evident through our engagement with various market players is a lack of clear understanding of roles and responsibilities across the Ontario energy agencies. Strong governance arrangements are required to provide clarity about strategic direction, roles and responsibilities and accountability for outcomes.

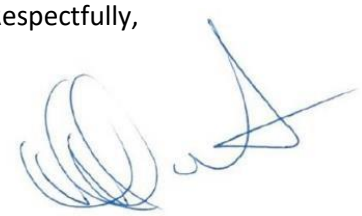
Minister, finding the optimal pathway to a net-zero economy will require us to leverage the expertise of all market players. It will also require a clear understanding of roles and responsibilities across the agencies. Without such clear delineation there is a real risk of a disjointed and less efficient and less cost-effective approach that is not in the best interest of Ontarians.

For example, based on our engagement with intervenors prior to filing with the OEB for our 2024 rates, we know that some will be advocating through the proceeding for an OEB decision that signals the retirement of all gas infrastructure and economy wide electrification. It has been argued that this is what the OEB's Innovation Task Force intends through its 4 D's of energy transition. But this is not established public policy, and we strongly contend that such policy direction is solely the domain of the provincial government.

To this end, Enbridge remains focused on meeting the evidentiary burden for 2024 rates and believes policy setting recommendations should best be directed to the Electrification and Energy Transition Panel. We believe a clear signal from you on the respective roles and responsibilities across the agencies would help ensure that stakeholders are directing their engagement efforts in the right places.

Please let us know how we can leverage the expertise and insights of our team to help you achieve our shared objectives.

Respectfully,



Michele Harradence
President
Enbridge Gas Inc.

cc:

Mr. Jason Fitzsimmons, Deputy Minister of Energy
Mr. Steen Hume, Assistant Deputy Minister, Energy Supply Division
Ms. Karen Moore, Assistant Deputy Minister, Strategic Networks and Partnerships Division
Ms. Susanna Zagar, President and CEO, Ontario Energy Board
Ms. Lesley Gallinger, President and CEO, Independent Electricity System Operator
Mr. David Collie, Chair, Electrification and Energy Transition Panel
Dr. Monica Gattinger, Electrification and Energy Transition Panel
Chief Emily Whetung, Electrification and Energy Transition Panel
Honourable Howard Wetston K.C., Electrification and Energy Transition Panel

ENBRIDGE GAS INC.

Answer to Undertaking from
Industrial Gas Users Association (IGUA)

Undertaking

Tr: 117

Enbridge to confirm whether S&P global ratings used a 38 percent equity thickness rather than a 36 percent equity thickness.

Response:

S&P Global, in its Enbridge Gas ratings report dated July 14, 2023, used a forecasted equity thickness of approximately 39% for 2024 and 2025.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 203

Enbridge to make best efforts to file an update to the table in Attachment 1 to include state-wide restrictions passed.

Response:

The following response was provided by Concentric Energy Advisors:

Attachment 1 contains an update to Exhibit I.5.3-ED-144, Attachment 1. Items that were added or updated are in bold italics. Of particular importance, in May 2023 the State of New York became the first U.S. state to pass legislation that bans the use of natural gas for heating and cooking in most new homes and buildings by 2026 to reduce carbon emissions. Conversely, in April 2023, the Ninth U.S. Circuit Court of Appeals in San Francisco struck down the City of Berkeley, California's ordinance banning natural gas lines in new construction, ruling that the ordinance illegally interferes with federal law, thus rejecting the city's attempt to scale back reliance on the fossil fuel through building codes. Attachment 2 contains an S&P Capital IQ article, "Gas Ban Monitor: All-electric building rules advance coast to coast in 2022," (January 24, 2022). This article provides updates on various efforts across the U.S. at both the state and local level to either restrict natural gas use in buildings, or to prohibit such restrictions.

City	New/Existing Building	Legislation Proposed /Passed	Population	Source
New York City, New York	New	Passed	8,804,190	New York City Bans Gas Hookups in New Buildings; is the State Next?: Hodgson Russ LLP
Ithaca, New York	New and Existing	Passed	32,108	Natural-Gas-Ban-Report_Updated.pdf (instituteforenergyresearch.org)
Berkeley, California	New	***Overturned***	124,321	Gas stove ban: Cities and states have already banned gas in new buildi (fastcompany.com)
San Francisco, California	New	Passed	873,965	Natural gas bans: 20 states have laws that prohibit cities from banning natural gas hookups | CNN Politics
Seattle, Washington	New	Passed	737,015	Natural-Gas-Ban-Report_Updated.pdf (instituteforenergyresearch.org)
Burlington, Vermont	New	Proposed	44,743	Natural-Gas-Ban-Report_Updated.pdf (instituteforenergyresearch.org)
Portland, Oregon	New	Passed	647,176	Natural-Gas-Ban-Report_Updated.pdf (instituteforenergyresearch.org)
Eugene, Oregon	New	Proposed	176,654	Cities & States Are Moving to All-Electric Buildings (climatenexus.org)
Brookline, Massachusetts	New	Passed	63,191	Cities & States Are Moving to All-Electric Buildings (climatenexus.org)
Shoreline, Washington	New	Passed	58,608	Cities & States Are Moving to All-Electric Buildings (climatenexus.org)
Bellingham, Washington	New	Passed	91,482	Cities & States Are Moving to All-Electric Buildings (climatenexus.org)
Sacramento, California	New	Passed	524,943	Cities & States Are Moving to All-Electric Buildings (climatenexus.org)
Oakland, California	New	Passed	440,646	Cities & States Are Moving to All-Electric Buildings (climatenexus.org)
Ann Arbor, Michigan	***New***	***Proposed***	***121,536***	S&P Capital IQ, "Gas Ban Monitor: All-electric building rules advance coastto coast in 2022," January 24, 2022
Crested Butte, Colorado	***New***	***Passed***	***1,681***	S&P Capital IQ, "Gas Ban Monitor: All-electric building rules advance coastto coast in 2022," January 24, 2022
Washington, D.C.	***New***	***Passed***	***712,816***	https://gas.climatenexus.org/gas-free-buildings
Montgomery County, Maryland	***New***	***Passed***	***1,055,000***	S&P Capital IQ, "Gas Ban Monitor: All-electric building rules advance coastto coast in 2022," January 24, 2022
Los Angeles, California	***New***	***Passed***	***3,849,000***	https://gas.climatenexus.org/gas-free-buildings
San Jose	***New***	***Passed***	***983,489***	https://gas.climatenexus.org/gas-free-buildings
Milwaukee, Oregon	***New***	***Passed***	***20,946***	S&P Capital IQ, "Gas Ban Monitor: All-electric building rules advance coastto coast in 2022," January 24, 2022
King County, Washington	***New***	***Passed***	***2,252,000***	S&P Capital IQ, "Gas Ban Monitor: All-electric building rules advance coastto coast in 2022," January 24, 2022
New York State	***New***	***Passed***	***19,840,000***	https://www.reuters.com/world/us/new-york-state-bans-natural-gas-some-new-construction-2023-05-03/

Gas Ban Monitor: All-electric building rules advance coast to coast in 2022

Tuesday, January 24, 2023 11:24 AM ET

By Tom DiChristopher
Market Intelligence

Ann Arbor, Mich., was among the communities where local lawmakers proposed gas bans for the first time in 2022.
Source:DenisTangneyJr/iStock/Getty Images Plus

This article is the second of a two-part series on building gas bans and all-electric codes that advanced in the second half of 2022. The first part can be found here.

The Pacific Northwest's push to restrict natural gas use in buildings notched more gains in the second half of 2022, and local governments from Michigan to Massachusetts also moved toward requiring all-electric construction.

The spread of gas bans to new areas demonstrated how the policy has matured and evolved since the San Francisco Bay Area popularized the building decarbonization strategy in 2019. In 2022, it took root in Midwestern and Rocky Mountain communities such as Ann Arbor, Mich., and Crested Butte, Colo., as well as East Coast areas, including Washington, D.C., and Montgomery County, Md.

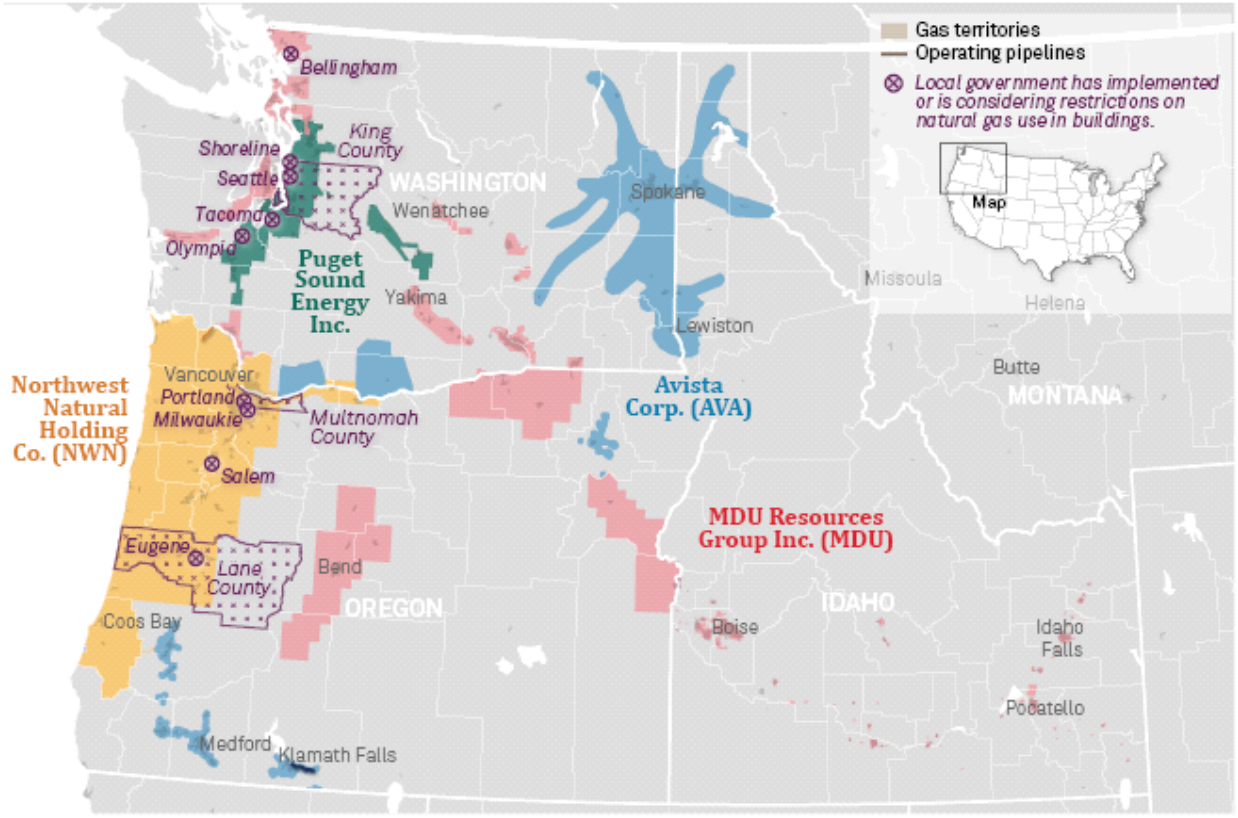
As cities adopt new approaches to mandating electrification, opponents have adapted to organize against the growing variety of gas bans. Even as state-level efforts to prohibit gas bans stalled in 2022, local challenges have delayed gas bans in places like Eugene, Ore.; Washington, D.C.; and New Jersey.

Gas ban movement grinds forward

The Milwaukie, Ore., City Council on Dec. 6, 2022, adopted a resolution directing city staff to develop code updates that prohibit new fossil fuel connections to residential buildings beginning on March 1, 2024. The resolution, adopted on a 3-2 vote, also directed staff to consult with commercial and industrial building owners and propose decarbonization regulations for these building types by June 30, 2025.

In a second resolution, councilors directed the city manager to install electric building equipment in city-owned buildings when natural gas-powered assets burn out, as well as when Milwaukie finances, substantially renovates, donates or sells city-owned property. The resolution, which drew unanimous support, also ordered the city manager to inventory gas equipment in city-owned facilities, evaluate the feasibility of converting to decarbonized equipment and submit preliminary recommendations by June 30, 2024.

Pacific Northwest gas utilities face building electrification movement



All-electric construction requirements

	Adopted	In development	Mandated in municipal, county buildings
Washington			
Bellingham*	X		
King County*	X		
Olympia		X	X
Seattle*	X		
Shoreline*	X		
Tacoma		X	X
Oregon			
Eugene		X	
Lane County			X
Milwaukie		X	

Multnomah County		X
Portland**		X
Salem	X	

As of Dec. 31, 2022.
* Applies to new multifamily and commercial buildings.
** Adopted by school district only.
Map credit: Ciaralou Agpalo Palicpic
Source: S&P Global Commodity Insights.
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The council has been following the lead of local lawmakers in Eugene, Ore., who directed city staff to develop a gas ban for new residential buildings in July 2022. The Eugene City Council held a public hearing on a proposed ordinance on Nov. 21, 2022, but did not take any action during a contentious meeting packed with opponents and supporters alike.

In Washington, the State Building Code Council voted on Nov. 4, 2022, to require electric heat pumps in new residential construction. The council included a heat pump mandate in an update to the state's commercial building code in April 2022. Representatives from Olympia and Tacoma, Wash., told S&P Global Commodity Insights that they were waiting for the building code updates to go into effect in July 2023 before they took action to restrict gas use in new buildings.

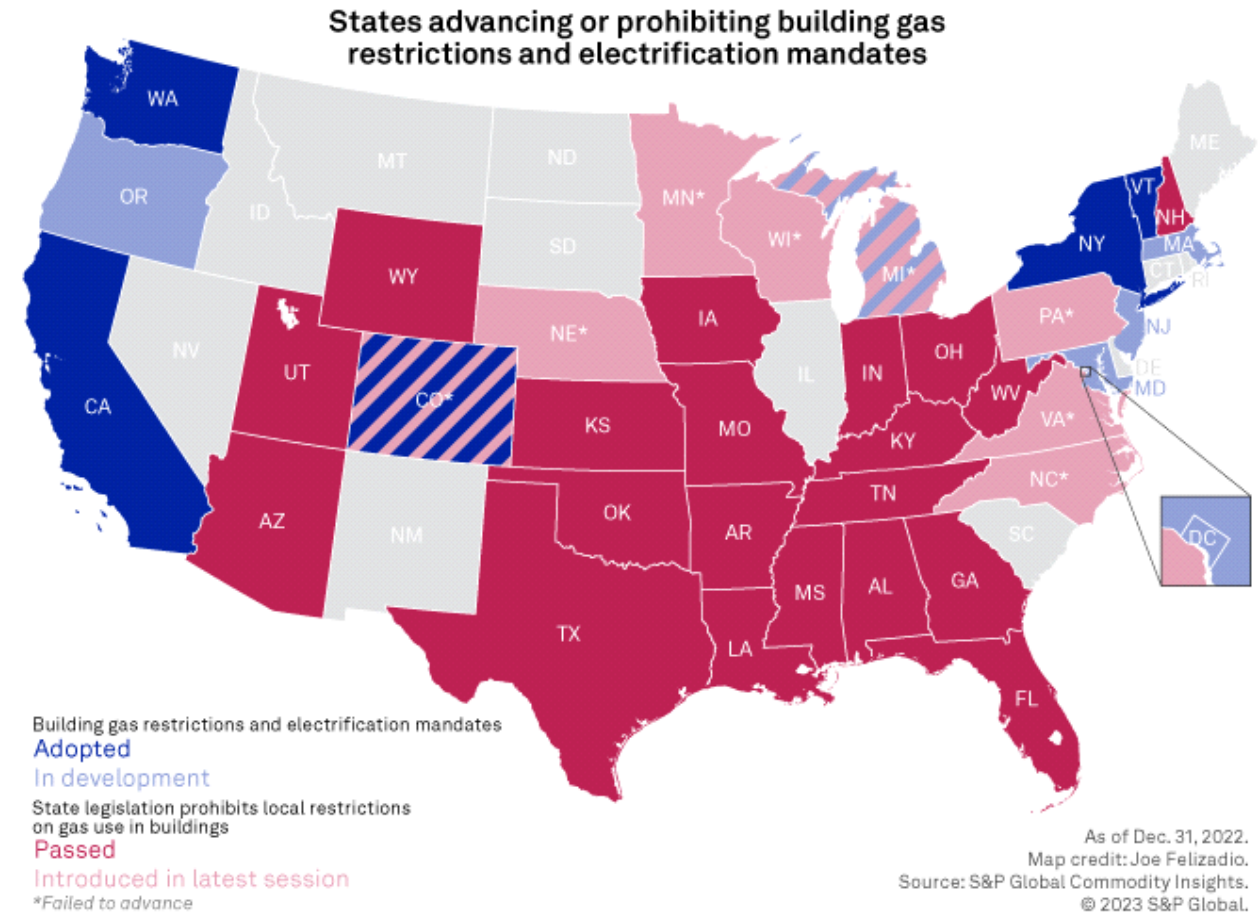
Seattle and Shoreline, Wash., have already prohibited fossil fuel and electric resistance systems for space and water heating in most new commercial buildings, including large apartment complexes. Lawmakers in the cities' home county and Washington state's largest, King County, voted unanimously on Aug. 23, 2022, to adopt a similar update to its building code, which applies to all unincorporated areas. The provision, which also applies to whole heating system replacements in existing commercial buildings, would essentially require electric heat pumps for space and water heating, with some exceptions.

New frontiers for bans

The city planning commission in Ann Arbor, Mich., in November 2022 introduced a proposal to prohibit gas use in new construction through an update to its unified development code, which governs zoning.

The commission held a pair of meetings on the amendment — originally proposed to go into effect Jan. 1 — and intended to further study and consider the proposal through the winter. Building electrification is one of six core strategies that the city is prioritizing to achieve its goal of carbon neutrality by 2030.

A bill to prohibit local governments from adopting gas bans died in committee in the Michigan Senate after passing on a mostly party-line vote in the House of Representatives in September 2022. The bill had little support among Democrats, who flipped both the Senate and House in November 2022 elections. The bill's failure to advance marked the latest defeat for several gas ban preemption bills across the country.



In November 2022, Montgomery County, Md., became the first jurisdiction in the state to pass a measure that will restrict gas use in most new buildings. Montgomery County Council legislation required the county executive to include an all-electric construction standard in the building code by Dec. 31, 2026 — a date that aligns with nearby Washington, D.C.'s timeline for a similar policy.

Washington, D.C.'s Construction Codes Coordinating Board voted in May 2022 to require all-electric construction in an update to the city's residential building code. However, a similar amendment to its commercial code ran into headwinds in October 2022. The updates require approval by the District of Columbia Council, which supports the changes; lawmakers passed an ordinance in July 2022 that ordered code officials to implement a net-zero energy standard for new commercial construction by Jan. 1, 2027.

Headwinds and tailwinds on the East Coast

The Massachusetts Department of Energy Resources on Dec. 23, 2022, launched a pilot program that will allow up to 10 towns and cities to prohibit gas use in new construction, following a nearly three-year campaign to advance the policy. The department designed the program to work with a new specialized stretch energy code that favors building electrification.

In the Clean Energy and Climate Plan for 2050 released Dec. 21, 2022, former Gov. Charlie Baker's administration advocated for using a clean heat standard to encourage electrification and other solutions to decarbonize building heating. The Baker Administration's Commission on Clean Heat recommended the clean heat standard in its final report issued Nov. 30, 2022. The policy would help the state hit greenhouse gas emissions reduction targets by requiring fossil fuel distributors to deploy strategies to help customers reduce gas, propane and heating oil consumption.

New Jersey Gov. Phil Murphy announced on Oct. 3, 2022, that his administration would launch a Clean Buildings Working Group. The stakeholder group will develop building decarbonization policy and legislation recommendations for the state, which must achieve an 80% reduction in greenhouse gas emissions from 2006 levels by 2050.

The New Jersey Department of Environmental Protection, or DEP, on Dec. 2, 2022, withdrew a proposed rule that would have prohibited many commercial and industrial facilities from installing fossil fuel boilers. The department proposed the regulation as an "initial step" toward reducing emissions from the state's building stock, its second-biggest source of greenhouse gas pollution, but the policy ran into opposition.

The rule would have affected thousands of schools and universities, apartment complexes and retail and industrial spaces. DEP "anticipates holding stakeholder sessions to discuss the regulation of boilers in 2023," an agency spokesperson told Commodity Insights in an email.

In neighboring New York, Gov. Kathy Hochul backed final recommendations by the state's Climate Action Council to begin prohibiting gas hookups in new buildings starting in 2025 and restricting the sale of new gas heating systems and appliances beginning in 2030.

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ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Duff

Undertaking

Tr: 35

To advise the Board: if the OEB were to approve a 42 percent increase in 2024, what would be the revenue requirement and the rate increase that would result from that, assuming all of your proposals are approved subject to the settlement proposal which has been filed with the OEB.

Response:

Please see Attachment 1 for an updated version of Exhibit 5, Tab 3, Schedule 1, Table 2 which provides the 2024 revenue requirement impact of transitioning from a 36% equity thickness to either a 38% or 42% equity thickness, based on the proposals included within this Application. As seen at line 14 of Attachment 1, the updated forecast 2024 revenue requirement impact of transitioning to a 42% equity thickness is an approximate increase of $80.6 million. The 2024 forecast rate base value used to calculate the revenue requirement impact in Attachment 1 has been updated to reflect the June 16, 2023 Capital Update (including the exclusion of 2024 Panhandle Regional Expansion Project (PREP) rate base impacts in accordance with the proposed levelized cost recovery approach), as well as impacts stemming from the June 28, 2023 Settlement Proposal (i.e. the removal of agreed to GTA Reinforcement and WAMS project overspend amounts, and the working cash impact related to the agreed to O&M reduction). Consistent with the calculation of the original change in equity thickness impacts which were presented in Exhibit 5, Tab 3, Schedule 1, Table 2, this updated calculation continues to use the 2022 OEB formula ROE as a placeholder (until it can be updated following the release of the 2024 OEB formula ROE), and continues to leverage the same financing plan/term debt assumptions as the original calculation, which were noted in paragraphs 8 and 9 of Exhibit 5, Tab 3, Schedule 1.

Please see Attachment 2 for the allocation of the revenue requirement impact of $80.6 million associated with a change in equity thickness from 36% to 42% in 2024. Consistent with the setting of rates for 2024 as proposed in the Settlement Proposal, the revenue requirement impact has been allocated to rate classes based on current approved revenue.

Please see Attachment 3 for the 2024 bill impact for typical customers in all in-franchise rate classes.

The typical residential customer bill impact associated with a change in equity thickness from 36% to 42% in 2024 is:

- An increase of $14.25, or 1.1%, for a residential customer consuming 2,400 m^3 in the EGD rate zone.
- An increase of $14.47, or 1.0%, for a residential customer consuming 2,200 m^3 in the Union North rate zone.
- An increase of $10.65, or 0.9%, for a residential customer consuming 2,200 m^3 in the Union South rate zone.

Table 2
2024 Equity Thickness Impacts on Cost of Capital and Revenue Requirement

Line No.	Particulars ($ millions)	Principal	Component	Cost Rate	Cost	Gross-up for taxes	Rev. Req. Impact
		(a)	(b)	(c)	(d)	(e)	(f)
	Equity thickness - 36%						
1	Medium and Long Term Debt	10,206.0	63.10%	4.17%	425.6	0.0	425.6
2	Short Term Debt	145.1	0.90%	3.00%	4.4	0.0	4.4
3	Common Equity	5,822.5	36.00%	8.66%	504.2	181.8	686.0
4	Cost of Capital component of Revenue Requirement	16,173.7			934.2		1,116.0
	Equity thickness - 38% (included in 2024 rev. req.)						
5	Medium and Long Term Debt	10,028.1	62.00%	4.17%	418.0	0.0	418.0
6	Short Term Debt	(0.4)	0.00%	3.00%	(0.0)	0.0	(0.0)
7	Common Equity	6,146.0	38.00%	8.66%	532.2	191.9	724.1
8	Cost of Capital component of Revenue Requirement	16,173.7			950.2		1,142.1
	Equity thickness - 42%						
9	Medium and Long Term Debt	9,852.2	60.91%	4.17%	410.4	0.0	410.4
10	Short Term Debt	(471.4)	(2.91%)	3.00%	(14.1)	0.0	(14.1)
11	Common Equity	6,792.9	42.00%	8.66%	588.3	212.1	800.4
12	Cost of Capital component of Revenue Requirement	16,173.7			984.5		1,196.6
13	2024 Revenue requirement impact of moving to 38% deemed equity thickness (from 36%)						26.1
14	2024 Revenue requirement impact of moving to 42% deemed equity thickness (from 36%)						80.6
15	42% versus 38% revenue requirement variance to be captured through base rate adjustments in 2025 - 2028						54.5
16	Proposed annual base rate adjustment in each of 2025 - 2028 (1/4 of $54.5 million)						13.6

Allocation and Unit Rates
Change in Equity Thickness from 36% to 42%

Line No.	Particulars ($000s)	Current Approved Distribution Revenue (1)	Allocation of Equity Thickness Impact (2)	2024 Forecast Usage (10^3m^3)	Billing Units	Unit Rate (cents / m^3)
		(a)	(b)	(c)	(d)	(e) = (b/c*100)
	EGD Rate Zone					
1	Rate 1	1,033,105	29,702	5,001,027	10^3m^3	0.5939
2	Rate 6	447,767	12,873	4,795,693	10^3m^3	0.2684
3	Rate 100	2,060	59	4,503	$10^3m^3/d$	1.3154
4	Rate 110	36,742	1,056	75,654	$10^3m^3/d$	1.3963
5	Rate 115	6,950	200	14,481	$10^3m^3/d$	1.3798
6	Rate 125	12,486	359	111,124	$10^3m^3/d$	0.3230
7	Rate 135	1,461	42	52,646	10^3m^3	0.0798
8	Rate 145	1,608	46	6,138	$10^3m^3/d$	0.7529
9	Rate 170	3,220	93	30,928	$10^3m^3/d$	0.2993
10	Rate 200	5,187	149	15,025	$10^3m^3/d$	0.9925
11	Rate 300	-	-	-	$10^3m^3/d$	0.0000
12	Total EGD Rate Zone	1,550,586	44,580			
	Union North Rate Zone					
13	Rate 01	226,285	6,506	989,005	10^3m^3	0.6578
14	Rate 10	30,601	880	327,974	10^3m^3	0.2683
15	Rate 20	30,831	886	91,732	$10^3m^3/d$	0.9663
16	Rate 25	4,865	140	126,831	10^3m^3	0.1103
17	Rate 100	11,804	339	42,050	$10^3m^3/d$	0.8071
18	Total Union North Rate Zone	304,386	8,751			
	Union South Rate Zone					
19	Rate M1	548,066	15,757	3,255,132	10^3m^3	0.4841
20	Rate M2	92,168	2,650	1,319,376	10^3m^3	0.2008
21	Rate M4 (F)	34,805	1,001	46,836	$10^3m^3/d$	2.1365
22	Rate M4 (I)	119	3	238	10^3m^3	1.4334
23	Rate M5 (F)	360	10	432	$10^3m^3/d$	2.3989
24	Rate M5 (I)	2,313	67	55,087	10^3m^3	0.1207
25	Rate M7 (F)	26,161	752	71,858	$10^3m^3/d$	1.0467
26	Rate M7 (I)	1,870	54	75,999	10^3m^3	0.0707
27	Rate M9	1,774	51	6,040	$10^3m^3/d$	0.8446
28	Rate T1 (F)	13,487	388	26,540	$10^3m^3/d$	1.4610
29	Rate T1 (I)	824	24	37,536	10^3m^3	0.0632
30	Rate T2 (F)	78,057	2,244	308,713	$10^3m^3/d$	0.7269
31	Rate T2 (I)	1,135	33	41,762	10^3m^3	0.0782
32	Rate T3	7,804	224	28,200	$10^3m^3/d$	0.7956
33	Total Union South Rate Zone	808,945	23,257			
	Ex-Franchise					
34	Rate 331	169	5			
35	Rate 332	19,179	551			
36	Rate M12/C1 Dawn-Parkway	104,651	3,009			
37	Rate M13	381	11			
38	Rate M16	428	12			
39	Rate M17	529	15			
40	Rate C1	14,191	408			
41	Total Ex-Franchise	139,528	4,011			
42	Total	2,803,445	80,600			

Notes:
(1) Exhibit 8, Tab 2, Schedule 8, Attachment 1, page 2, column (a) excluding Rate 401 and non-utility cross charge revenue.
(2) Allocated in proportion to column (a).

Bill Impacts for Typical Small and Large Customers
Change in Equity Thickness from 36% to 42%

Line No.	Particulars	Unit Rate (1) (cents/m³)	Billing Units		Bill Impact (2) ($)	Bill Impact (2) (%)
		(a)	(b)	(c)	(d)	(e)
	EGD Rate Zone					
1	Rate 1 - Residential	0.5939	2,400	m³	14.25	1.1%
2	Rate 6 - Heating & Other Uses	0.2684	22,606	m³	60.68	0.6%
3	Rate 100 - Small	1.3154	2,993	m³/d	472.44	0.4%
4	Rate 100 - Large	1.3154	30,000	m³/d	4735.44	0.7%
5	Rate 110 - Small	1.3963	3,292	m³/d	551.60	0.3%
6	Rate 110 - Large	1.3963	53,871	m³/d	9026.44	0.3%
7	Rate 115 - Small	1.3798	15,300	m³/d	2533.25	0.2%
8	Rate 115 - Large	1.3798	238,928	m³/d	39559.71	0.2%
9	Rate 125 - Average	0.3230	2,315,000	m³/d	89742.56	0.1%
10	Rate 135 - Average	0.0798	598,567	m³	477.50	0.2%
11	Rate 145 - Small	0.7529	2,993	m³/d	270.43	0.2%
12	Rate 145 - Large	0.7529	4,489	m³/d	405.60	0.2%
13	Rate 170 - Small	0.2993	36,413	m³/d	1307.96	0.0%
14	Rate 170 - Large	0.2993	255,089	m³/d	9162.81	0.0%
15	Rate 200 - Average	0.9925	1,252,000	m³/d	149115.45	0.4%

Notes:
(1) Exhibit J9.1, Attachment 1, column (e).
(2) Bill impact % is derived as column (d) divided by the current approved total bill for a sales service customer as provided at Exhibit 8, Tab 2, Schedule 8, Attachment 10, column (a).

Bill Impacts for Typical Small and Large Customers
Change in Equity Thickness from 36% to 42%

Line No.	Particulars	Unit Rate (1) (cents/m³)	Billing Units		Bill Impact (2) ($)	Bill Impact (2) (%)
		(a)	(b)	(c)	(d)	(e)
	Union North Rate Zone					
1	Rate 01 - Residential	0.6578	2,200	m³	14.47	1.0%
2	Rate 10	0.2683	93,000	m³	249.47	0.6%
3	Rate 20 - Small	0.9663	14,000	m³/d	1623.37	0.1%
4	Rate 20 - Large	0.9663	60,000	m³/d	6957.28	0.1%
5	Rate 25 - Average	0.1103	2,275,000	m³	2508.83	0.3%
6	Rate 100 - Small	0.8071	100,000	m³/d	9684.87	0.1%
7	Rate 100 - Large	0.8071	850,000	m³/d	82321.41	0.1%
	Union South Rate Zone					
8	Rate M1 - Residential	0.4841	2,200	m³	10.65	0.9%
9	Rate M2	0.2008	73,000	m³	146.61	0.5%
10	Rate M4 - Small	2.1365	4,800	m³/d	1230.64	0.4%
11	Rate M4 - Large	2.1365	50,000	m³/d	12819.17	0.3%
12	Rate M5 - Small	0.1207	825,000	m³	996.03	0.3%
13	Rate M5 - Large	0.1207	6,500,000	m³	7847.54	0.3%
14	Rate M7 - Small	1.0467	165,000	m³/d	20724.44	0.2%
15	Rate M7 - Large	1.0467	720,000	m³/d	90433.91	0.5%
16	Rate M9 - Small	0.8446	56,439	m³/d	5720.06	0.3%
17	Rate M9 - Large	0.8446	168,100	m³/d	17036.83	0.3%
18	Rate T1 - Small	1.4610	25,750	m³/d	4514.50	0.2%
19	Rate T1 - Average	1.4610	48,750	m³/d	8546.87	0.2%
20	Rate T1 - Large	1.4610	133,000	m³/d	23317.61	0.3%
21	Rate T2 - Small	0.7269	190,000	m³/d	16574.35	0.1%
22	Rate T2 - Average	0.7269	669,000	m³/d	58359.14	0.1%
23	Rate T2 - Large	0.7269	1,200,000	m³/d	104680.07	0.1%
24	Rate T3	0.7956	2,350,000	m³/d	224361.84	0.3%

Notes:
(1) Exhibit J9.1, Attachment 1, column (e).
(2) Bill impact % is derived as column (d) divided by the current approved total bill for a sales service customer as provided at Exhibit 8, Tab 2, Schedule 8, Attachment 10, column (a).

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 105

EGI to provide the normalized system reinforcement costs for 2024, including the underlying calculations, and showing how it is applied to the connection costs of a customer.

Response:

Normalized System Reinforcement Cost (NSRC) are costs associated with reinforcement projects undertaken by the Company in the past to support future growth. The cost of such projects is applied on a normalized basis as prescribed in E.B.O 188. Derivation of 2024 NSRC and how it is applied to new connections is summarized in Table 1.

Table 1
2024 Normalized System Reinforcement Cost (NSRC)

Categories	Amortization Period	($million)
Special Reinforcement Costs	20 Years	25.3
Special Reinforcement Costs	10 Years	12.0
Normal Reinforcement Cost	None	0.3
Total NSRC(1)	A	37.7
Test Year Budget (2024 Budget)(2)	B	251.2
NSRC % for Feasibility Assessment(3)	A / B	15%

Notes:
(1) Includes amortized value of special reinforcement projects (amortized over 10-20 years) and normal reinforcement projects which are not subject to amortization. The determination of the amortization period of 10-year vs 20-year is done based on the estimated time a reinforcement project will support new growth in the associated area. The special reinforcement costs in this table represent the cumulative value of the amortized amount of all reinforcement projects undertaken over 10-20 years. A project remains on the list of special reinforcement projects until it is fully amortized over the prescribed amortization period (10 or 20 years) and is removed from the list at the end of this period.

(2) 2024 Budget for customer connections and meter costs (without overheads)
(3) For customer feasibility assessments, NSRC is applied as a percentage of the estimated direct capital cost of the project. This percentage may fluctuate year over year depending upon how many new reinforcement projects are added to the list of special reinforcement projects and the amount of capital investment involved. The NSRC is expected to fluctuate between 13% to 15.5% based upon historical averages.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 115

Enbridge Gas to provide information about the customer connections forecast number of $304 million for 2024 contained in table 1, including whether it includes incremental overheads, meters, costs and normalized reinforce costs; if some or all of those are not included, Enbridge Gas will indicate the costs that would be associated with each of those items, and Enbridge Gas will indicate its views as to which, if any, of these items are appropriate to be considered in the context of the 2024 capital budget and in the context of implications of changing the customer revenue horizon.

Response:

The customer connections forecast number of $304 million for 2024 includes construction costs for the services/mains including pipeline material, contractor costs to install the pipe and set the meter, permits, fees and indirect overheads but does not include meters, Extended Alliance (EA) fixed overheads or reinforcement costs. Costs associated with meters amount to $16.5 million, costs associated with EA fixed overheads amount to $38.2 million and costs for reinforcement is $85.2 million in 2024. Normalized System Reinforcement costs is a figure derived from previous years' reinforcement capital and applied to the Investment Portfolio calculation. Enbridge Gas does not use a bottom-up estimating approach for estimating construction costs included in the customer connection forecast. This is due to availability of scope information at the time forecasts are developed. Instead, these costs are estimated based on average net costs for attachments in prior years. Therefore, Enbridge Gas is unable to provide the forecast breakdown of costs in 2024 due to the process by which the capital budget is derived. However, in an effort to be responsive, Enbridge Gas has determined a three-year historical average of spend by cost category and has applied this to the 2024 budget of $304.1 million. Please see Table 1.

Table 1
Historical average of Spend by Cost Category

CAPEX Cost Category		($ millions)	Notes
Customer Connections			
	Contractor Costs	213.5	Based on 3yr average
	Material	38.3	Based on 3yr average
	Labour	4.6	Based on 3yr average
	Contribution in Aid to Construct	(17.3)	Based on 3yr average
	Indirect Overheads	63.4	Based on forecast overhead for 2024
	Other	1.6	Based on 3yr average
Total		$304.1	
Items Not Included in Table 1(1)			
	Utilization – Growth Meters(2)	16.5	
	EA Fixed - Growth	38.2	
Total		$358.8	
System Reinforcement Costs(2)		$85.2	
Total		$444	

Notes:
(1)If the revenue horizon were to change and this resulted in a reduction of customers attaching to the system, Enbridge Gas expects that this would reduce its capital expenditures in the Customer Connections and Utilization (growth meters) asset classes by some amount, however Enbridge Gas does not have information to predict how much. There would also likely be reductions to future Growth – Reinforcement projects however, these impacts would not be immediate in the 2024 year. Because EA fixed overheads are not set based on customer count, they are not expected to decrease in 2024.
(2) Amounts are inclusive of capitalized overheads allocations

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 123

In relation to Table 1, Enbridge Gas will advise as to the total contribution in aid of construction amount associated with each of the different revenue horizons for 2024, and, if the amount of additional work is not overly substantial, Enbridge Gas will provide the same information in relation to the years 2025 to 2028.

Response:

The total Contribution in Aid of Construction (CIAC) cannot be provided for the reasons mentioned in Enbridge Gas's response at Exhibit I.2.5-CCC-42. In this response, it was indicated that the CIAC amount cannot be provided as the Asset Management Plan forecasts are established net of contributions. For customer connections in particular, the forecast is based on based on historical average net connection costs and the forecasted connections for each year. Contributions will vary by project, and Enbridge Gas does not track averages for these values or use them directly for forecasting purposes. For this reason, the total amount of CIAC for different revenue horizons cannot be provided on a forecast basis. However, as a proxy, please see Exhibit I.2.5-CCC-43, part c) for the historical CIAC amounts collected from 2019 to 2022 by asset class.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 134

Enbridge Gas to advise as to the change in either extra-length charge or standard charge to be applied to infill customers, in the context of revenue horizons of zero, 10, 15, and 25.

Response:

The calculation of the proposed Extra Length Charge (ELC) of $159 per metre is based on a 40-year revenue horizon. Given the complexity and time to complete the analysis of new ELCs based on each revenue horizon the Company is unable to provide specific ELCs for each revenue horizon at this time. Directionally it will be much higher – the Company estimates that the ELC will be over $800 per metre for a 25-year revenue horizon and over $1000 per metre for a 15-year revenue horizon.

Should the OEB direct a new revenue horizon or other changes to how Enbridge Gas applies the E.B.O. 188 Guidelines to feasibility determinations for residential customers, the Company would need to conduct detailed analysis to determine a precise new proposed ELC. The much higher ELC would likely lead Enbridge Gas to reassess the suitability of the ELC approach and propose alternative methods for review and approval by the OEB. Alternatives include a straight fixed charge, a per metre charge that would apply to the entire service length, a combination of these or a full feasibility analysis for each infill service based on estimated costs and revenues to determine a CIAC. Once the Company determines an appropriate proposal, it would be appropriate to undergo additional customer engagement[1] before filing with the OEB for final review and approval.

As an example of the alternate approach that Enbridge Gas might propose, the Company has calculated an estimate of the fixed charge approach for each revenue horizon which is set out in Table 1.

[1] The customer engagement that Enbridge Gas undertook with the current ELC proposal is described at Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 279-280 and Exhibit 8, Tab 3, Schedule 1, pages 10-13.

Table 1
Standard Charge for Infills

Revenue Horizon (Years)	Standard Charge ($)
30	2,500
25	3,000
15	4,200
10	5,000
0	7,900

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 145

For 2024, as information is available, Enbridge to advise how much of the $16.2 billion is attributable to all of the direct customer connection costs that are still remaining in rate base.

Response:

Enbridge Gas is unable to isolate the costs that are specific to Customer Attachments from the plant accounts. However, Enbridge Gas believes that the balances in the steel and plastic services plant accounts are a reasonable proxy for the direct customer connection costs remaining in 2024 rate base. The costs are represented as follows:

Particulars ($ millions)	Reference	Amount
Services – metallic (gross)	Exhibit 2, Tab 2, Sch 1, Attachment 8, Page 1, Line 5, updated July 6, 2023	674.1
Services – plastic (gross)	Exhibit 2, Tab 2, Sch 1, Attachment 8, Page 1, Line 6, updated July 6, 2023	5,006.6
Services – metallic (accumulated depreciation)	Exhibit 2, Tab 2, Sch 1, Attachment 8, Page 6, Line 4, updated July 6, 2023	(307.4)
Services – plastic (accumulated depreciation)	Exhibit 2, Tab 2, Sch 1, Attachment 8, Page 6, Line 5, updated July 6, 2023	(1,843.7)
Net 2024 Rate Base		3,529.6

The above represents approximately 22% of the 2024 Rate Base of $16,212.3 million.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 150

Referring to the Enbridge compendium, Exhibit K10.2, Tab 39, Enbridge to provide a similar table for two types of apartment buildings, a sample project of a five-storey building and a 20-storey building from the last couple of years, that use the natural gas for both space and water heating, to show the developer's contribution in aid under different revenue horizons.

Response:

Please see Example 1 and Example 2, which depict a developer's contribution required for a sample 20-Storey and 5-Storey building, respectively. Both examples are based on real condominium projects that are in-service. To demonstrate sensitivity of contribution in aid of construction (CIAC) vs revenue horizons, the buildings have been selected with a PI less than or close to 1.0, and will require additional CIAC when the revenue horizon is reduced.

EXAMPLE 1

Gross Capital	$3,861,317
Project description	Condominium building (bulk metered)

Revenue Horizon (Years)	High Rise (> 20 storey building)			
	Capital supported for a PI of 1.0	CIAC	Additional CIAC vs 40-year scenario	Additional CIAC as a (%) vs 40-year scenario
	($000)	($000)	($000)	(%)
40	1,424.6	2,436.7		
30	1,281.2	2,580.1	143.5	6
25	1,175.5	2,685.9	249.2	10
15	858.4	3,002.9	566.2	21
10	624.8	3,236.6	799.9	27

EXAMPLE 2

Gross Capital	$1,293,041
Project description	Condominium building (individually metered)

Revenue Horizon (Years)	Low Rise (4-5 storey building)			
	Capital supported for a PI of 1.0	CIAC	Additional CIAC vs 40-year scenario	Additional CIAC as a (%) vs 40-year scenario
	($000)	($000)	($000)	(%)
40	1,293.0	0.0		
30	1,293.0	0.0		NA
25	1,291.1	1.9	1.9	NA
15	946.8	346.2	346.2	NA
10	697.5	595.5	595.5	NA

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Greenhouse Vegetable Growers (OGVG)

Undertaking

Tr: 158

With reference to table 1 from Enbridge Gas' compendium, Exhibit K10.2, Enbridge, on a best-efforts basis, to indicate what the numbers for 2024 would be if industrial and large customers who are subject to a different revenue horizon are removed from the analysis. Additionally, with reference to Table 1 in ADR 6, Enbridge Gas will indicate which of the categories in the system-access category are subject to a revenue horizon of less than 40 years.

Response:

A small portion of the customer connections capital expenditure is related to the distribution contract customers. The vast majority of capital expenditure for distribution contact customers is included in other growth categories. Consequently, a very small amount of capital expenditure related to customer connections is associated with customers with a revenue horizon less than 40 years.

A 40-year revenue horizon is used for all customer connection categories included in Table 1 provided at Exhibit I.ADR 6, except for a small number of distribution contract market customers within the industrial category.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 177

Enbridge to provide a document showing the calculations of the figures in the table at page 139 of Enbridge's compendium.

Response:

The table below replicates the table referenced in this undertaking. Please note that in reviewing this undertaking, Enbridge Gas determined that the data in the rows corresponding to the 30-year revenue horizon and 25-year revenue horizon were inaccurate. Corrected data are reflected in the table below which is an update to the table included at Exhibit K10.2 page 139 of the Enbridge Gas compendium.

Revenue Horizon	2024	2025	2026	2027	2028	Total	Reduction vs. 40 Year Revenue Horizon	CIAC per Customer
(Years)	($millions)	($millions)	($millions)	($millions)	($millions)	($millions)	($millions)	
40	304	248	258	254	250	1,314		
30	229	227	239	241	253	1,190	124	645
25	210	208	219	221	235	1,094	220	1,140
15	146	144	153	154	159	757	557	2,890
10	89	88	93	95	96	460	853	4,428

Please see Attachment 1, which provides Enbridge Gas system access investments including customer connections corresponding to a 40-year revenue horizon scenario. These figures are based on Exhibit I.ADR.6 and reflect the system access details at Exhibit I.2.6-SEC-112 which has been updated to reflect the Capital Update filed on June 16, 2023. Attachments 2 through 5 provide calculations of the figures for the other revenue horizons. Note that in each of the scenarios, the decrease in capital expenditures results in a re-calculation of overhead allocations as compared to the 40-year revenue horizon in Attachment 1. Overheads are calculated based on the

percentage of total overheads and total direct capital. Therefore, as direct capital decreases, the percentage allocation of overhead increases.

Table 1 - System Access Forecast 2024 to 2028 - 40-Year Revenue Horizon

USP Category	Asset Program (EGI)	2024 F	2025 F	2026 F	2027 F	2028F
System Access	CC - Commercial/Bulk-Metered - Conversion	1.9	3.3	3.5	3.6	3.6
	CC - Commercial/Bulk-Metered - New	61.0	26.2	27.4	27.8	28.2
	CC - Industrial - New	0.0	4.3	4.5	4.4	4.5
	CC - Multi-Family/Apartment - New	0.0	4.0	4.2	4.3	4.3
	CC - Residential - Conversion	27.8	44.4	46.6	47.3	48.0
	CC - Residential - New	210.8	163.8	169.0	164.1	158.9
	CC - Sales Station - Conversion	0.6	0.6	0.6	0.6	0.6
	CC - Sales Station - New	1.8	1.8	1.8	1.9	1.9
Subtotal Customer Connections		303.9	248.4	257.6	254.0	250.0
	CS - Growth	0	0	0	0	0
	DP - Relocations	40.9	43.4	43.5	44.7	56.4
	DS - CNG	3.4	1.4	1	1	1.1
	GTH - Hydrogen Blending	9.5	11.1	3.2	0	0
	TPS - Growth	6.9	73.6	136.9	216.8	125.5
	UTIL - Meters (growth)	16.5	17	18.5	19.2	12.2
	EA Fixed O/H - Gth	38.2	39.2	40.2	41.3	23.2
	Community Expansion	11.2	19.6	20.5	21.5	7.3
System Access Total		430.6	453.7	521.6	598.6	475.9

Direct Capital Cost Supportable by New Connections Revenue

30 year Rev Horizon	2024	2025	2026	2027	2028
EGD	114,924,358	115,540,209	116,181,979	116,831,777	115,202,708
Union South	52,134,475	51,738,709	51,680,900	51,752,049	51,045,005
Union North	10,854,529	10,612,256	10,400,693	10,264,201	9,984,392
Total	177,913,362	177,891,174	178,263,572	178,848,027	176,232,105

UG					
USP Categories	2024	2025	2026	2027	2028
Customer Connections	62,989,004	62,350,965	62,081,593	62,016,250	61,029,397
DP Relocations	27,770,000	24,060,000	22,930,000	23,665,000	24,100,000
DS - CNG	1,533,703	-	-	-	-
GTH - Hydrogen Blending	1,450,000	-	-	-	-
TPS - Growth	5,433,461	58,122,323	102,936,935	162,585,344	125,537,786
UTIL - Meters Growth	5,017,712	5,188,314	5,364,716	5,547,117	3,916,991
Total	104,193,880	149,721,602	193,313,244	253,813,711	214,584,174

UG + OH	27.78%	26.99%	33.50%	33.70%	43.37%
USP Categories	2024	2025	2026	2027	2028
Customer Connections	80,485,587	79,179,896	82,876,845	82,917,081	87,497,611
DP Relocations	35,483,729	30,553,951	30,610,781	31,640,622	34,552,077
DS - CNG	1,959,722	-	-	-	-
GTH - Hydrogen Blending	1,852,769	-	-	-	-
TPS - Growth	6,942,724	73,809,916	137,417,357	217,380,157	179,983,040
UTIL - Meters Growth	6,411,492	6,588,674	7,161,716	7,416,617	5,615,775
Total	133,136,025	190,132,437	258,066,699	339,354,476	307,648,502

EGD					
USP Categories	2024	2025	2026	2027	2028
Customer Connections	114,924,358	115,540,209	116,181,979	116,831,777	115,202,708
DP Relocations	4,515,609	10,195,454	9,710,204	9,710,204	16,880,066
DS - CNG	1,130,275	1,078,558	760,289	773,442	786,823
GTH - Hydrogen Blending	6,000,000	8,700,000	2,400,000	-	-
UTIL - Meters Growth	7,908,353	8,177,237	8,455,263	8,742,742	4,934,538
Total	134,478,595	143,691,458	137,507,735	136,058,165	137,804,135

EGD + OH	29.64%	27.82%	34.43%	35.48%	43.58%
USP Categories	2024	2025	2026	2027	2028
Customer Connections	148,988,506	147,687,530	156,181,254	158,281,933	165,408,016
DP Relocations	5,854,058	13,032,185	13,053,245	13,155,238	24,236,394
DS - CNG	1,465,294	1,378,650	1,022,042	1,047,848	1,129,720
GTH - Hydrogen Blending	7,778,430	11,120,644	3,226,275	-	-
UTIL - Meters Growth	10,252,428	10,452,430	11,366,251	11,844,535	7,085,009
Total	174,338,715	183,671,439	184,849,067	184,329,554	197,859,138

EGI					
USP Categories	2024	2025	2026	2027	2028
Customer Connections	177,913,362	177,891,174	178,263,572	178,848,027	176,232,105
DP Relocations	32,285,609	34,255,454	32,640,204	33,375,204	40,980,066
DS - CNG	2,663,978	1,078,558	760,289	773,442	786,823
GTH - Hydrogen Blending	7,450,000	8,700,000	2,400,000	-	-
TPS - Growth	5,433,461	58,122,323	102,936,935	162,585,344	
UTIL - Meters Growth	12,926,065	13,365,551	13,819,979	14,289,859	8,851,529
EA Fixed - Growth	38,243,358	39,210,708	40,214,787	41,257,638	23,218,092
Community Expansion	11,202,509	19,578,607	20,494,389	21,478,734	7,343,532
Total	288,118,342	352,202,375	391,530,155	452,608,248	257,412,147

EGI + OH					
USP Categories	2024	2025	2026	2027	2028
Customer Connections	229,474,093	226,867,426	239,058,099	241,199,014	252,905,626
DP Relocations	41,337,787	43,586,136	43,664,026	44,795,860	58,788,471
DS - CNG	3,425,017	1,378,650	1,022,042	1,047,848	1,129,720
GTH - Hydrogen Blending	9,631,199	11,120,644	3,226,275	-	-
TPS - Growth	6,942,724	73,809,916	137,417,357	217,380,157	179,983,040
UTIL - Meters Growth	16,663,920	17,041,104	18,527,967	19,261,152	12,700,784
EA Fixed - Growth	38,243,358	39,210,708	40,214,787	41,257,638	23,218,092
Community Expansion	11,202,509	19,578,607	20,494,389	21,478,734	7,343,532
Total	356,920,607	432,593,191	503,624,942	586,420,403	536,069,264

Table 1: 30-Year Revenue Horizon

$ Million	2024	2025	2026	2027	2028	Total
1) Customer Connections	229.5	226.9	239.1	241.2	252.9	1,189.5
2) DP Relocations	41.3	43.6	43.7	44.8	58.8	232.2
3) DS - CNG	3.4	1.4	1.0	1.0	1.1	8.0
4) GTH - Hydrogen Blending	9.6	11.1	3.2	-	-	24.0
5) TPS - Growth	6.9	73.8	137.4	217.4	180.0	615.5
6) UTIL - Meters Growth	16.7	17.0	18.5	19.3	12.7	84.2
7) EA Fixed - Growth	38.2	39.2	40.2	41.3	23.2	182.1
8) Community Expansion	11.2	19.6	20.5	21.5	7.3	80.1
9) Total	356.9	432.6	503.6	586.4	536.1	2,415.6

Direct Capital Cost Supportable by New Connections Revenue

25 year Rev Horizon	2024	2025	2026	2027	2028
EGD	104,020,869	104,578,292	105,159,174	105,747,321	104,272,811
Union South	48,844,788	48,473,994	48,419,833	48,486,493	47,024,423
Union North	9,752,364	9,534,691	9,344,610	9,221,977	12,403,876
Total	162,618,021	162,586,977	162,923,617	163,455,792	163,701,110

UG No Change

USP Categories	2024	2025	2026	2027	2028
Customer Connections	58,597,152	58,008,685	57,764,443	57,708,470	59,428,299
DP Relocations	27,770,000	24,060,000	22,930,000	23,665,000	24,100,000
DS - CNG	1,533,703	-	-	-	-
GTH - Hydrogen Blending	1,450,000	-	-	-	-
TPS - Growth	5,433,461	58,122,323	102,936,935	162,585,344	125,537,786
UTIL - Meters Growth	5,017,712	5,188,314	5,364,716	5,547,117	3,916,991
Total	99,802,028	145,379,322	188,996,094	249,505,931	212,983,076

UG + OH 28.15% 27.33% 34.01% 34.24% 43.37%

USP Categories	2024	2025	2026	2027	2028
Customer Connections	75,095,095	73,863,235	77,412,881	77,465,935	85,202,123
DP Relocations	35,588,603	30,635,920	30,729,585	31,767,111	34,552,077
DS - CNG	1,965,514	-	-	-	-
GTH - Hydrogen Blending	1,858,245	-	-	-	-
TPS - Growth	6,963,244	74,007,932	137,950,689	218,249,171	179,983,040
UTIL - Meters Growth	6,430,441	6,606,350	7,189,511	7,446,266	5,615,775
Total	127,901,143	185,113,437	253,282,667	334,928,482	305,353,014

EGD

USP Categories	2024	2025	2026	2027	2028
Customer Connections	104,020,869	104,578,292	105,159,174	105,747,321	104,272,811
DP Relocations	4,515,609	10,195,454	9,710,204	9,710,204	16,880,066
DS - CNG	1,130,275	1,078,558	760,289	773,442	786,823
GTH - Hydrogen Blending	6,000,000	8,700,000	2,400,000	-	-
UTIL - Meters Growth	7,908,353	8,177,237	8,455,263	8,742,742	4,934,538
Total	123,575,106	132,729,541	126,484,930	124,973,709	126,874,238

EGD + OH 30.08% 28.21% 35.02% 36.12% 43.58%

USP Categories	2024	2025	2026	2027	2028
Customer Connections	135,311,229	134,077,063	141,980,727	143,938,763	149,714,872
DP Relocations	5,873,943	13,071,322	13,110,238	13,217,117	24,236,394
DS - CNG	1,470,272	1,382,791	1,026,505	1,052,777	1,129,720
GTH - Hydrogen Blending	7,804,851	11,154,040	3,240,362	-	-
UTIL - Meters Growth	10,287,253	10,483,819	11,415,879	11,900,249	7,085,009
Total	160,747,547	170,169,035	170,773,710	170,108,905	182,165,995

EGI

USP Categories	2024	2025	2026	2027	2028
Customer Connections	162,618,021	162,586,977	162,923,617	163,455,791	163,701,110
DP Relocations	32,285,609	34,255,454	32,640,204	33,375,204	40,980,066
DS - CNG	2,663,978	1,078,558	760,289	773,442	786,823
GTH - Hydrogen Blending	7,450,000	8,700,000	2,400,000	-	-
TPS - Growth	5,433,461	58,122,323	102,936,935	162,585,344	
UTIL - Meters Growth	12,926,065	13,365,551	13,819,979	14,289,859	8,851,529
EA Fixed - Growth	38,243,358	39,210,708	40,214,787	41,257,638	23,218,092
Community Expansion	11,202,509	19,578,607	20,494,389	21,478,734	7,343,532
Total	272,823,001	336,898,178	376,190,200	437,216,012	244,881,152

EGI + OH

USP Categories	2024	2025	2026	2027	2028	Total
Customer Connections	210,406,324	207,940,298	219,393,608	221,404,698	234,916,995	1,094,061,923
DP Relocations	41,462,545	43,707,242	43,839,823	44,984,228	58,788,471	232,782,310
DS - CNG	3,435,786	1,382,791	1,026,505	1,052,777	1,129,720	8,027,578
GTH - Hydrogen Blending	9,663,096	11,154,040	3,240,362	-	-	24,057,498
TPS - Growth	6,963,244	74,007,932	137,950,689	218,249,171	179,983,040	617,154,075
UTIL - Meters Growth	16,717,694	17,090,169	18,605,390	19,346,515	12,700,784	84,460,552
EA Fixed - Growth	38,243,358	39,210,708	40,214,787	41,257,638	23,218,092	182,144,583
Community Expansion	11,202,509	19,578,607	20,494,389	21,478,734	7,343,532	80,097,771
Total	338,094,557	414,071,787	484,765,552	567,773,760	518,080,633	2,322,786,289

Table 1: 25-Year Revenue Horizon

$ Million	2024	2025	2026	2027	2028	Total
1) Customer Connections	210.4	207.9	219.4	221.4	234.9	1,094.1
2) DP Relocations	41.5	43.7	43.8	45.0	58.8	232.8
3) DS - CNG	3.4	1.4	1.0	1.1	1.1	8.0
4) GTH - Hydrogen Blending	9.7	11.2	3.2	-	-	24.1
5) TPS - Growth	7.0	74.0	138.0	218.2	180.0	617.2
6) UTIL - Meters Growth	16.7	17.1	18.6	19.3	12.7	84.5
7) EA Fixed - Growth	38.2	39.2	40.2	41.3	23.2	182.1
8) Community Expansion	11.2	19.6	20.5	21.5	7.3	80.1
9) Total	338.1	414.1	484.8	567.8	518.1	2,322.8

Direct Capital Cost Supportable by New Connections Revenue

15 year Rev Horizon	2024	2025	2026	2027	2028
EGD	70,758,963	71,138,143	71,533,281	71,933,362	70,930,343
Union South	33,103,829	32,852,529	32,815,822	32,861,000	32,412,048
Union North	7,932,870	7,755,808	7,601,191	7,501,438	7,296,944
Total	111,795,662	111,746,480	111,950,294	112,295,799	110,639,335

UG — No Change

USP Categories	2024	2025	2026	2027	2028
Customer Connections	41,036,699	40,608,337	40,417,013	40,362,437	39,708,992
DP Relocations	27,770,000	24,060,000	22,930,000	23,665,000	24,100,000
DS - CNG	1,533,703	-	-	-	-
GTH - Hydrogen Blending	1,450,000	-	-	-	-
TPS - Growth	5,433,461	58,122,323	102,936,935	162,585,344	125,537,786
UTIL - Meters Growth	5,017,712	5,188,314	5,364,716	5,547,117	3,916,991
Total	82,241,575	127,978,974	171,648,664	232,159,898	193,263,769

UG + OH

	29.50%	28.54%	35.87%	36.15%	43.37%
USP Categories	2024	2025	2026	2027	2028
Customer Connections	53,140,986	52,197,706	54,916,254	54,954,276	56,930,628
DP Relocations	35,961,108	30,926,576	31,155,932	32,220,377	34,552,077
DS - CNG	1,986,087	-	-	-	-
GTH - Hydrogen Blending	1,877,696	-	-	-	-
TPS - Growth	7,036,128	74,710,075	139,864,638	221,363,238	179,983,040
UTIL - Meters Growth	6,497,749	6,669,027	7,289,260	7,552,512	5,615,775
Total	106,499,754	164,503,384	233,226,085	316,090,402	277,081,520

EGD

USP Categories	2024	2025	2026	2027	2028
Customer Connections	70,758,963	71,138,143	71,533,281	71,933,362	70,930,343
DP Relocations	4,515,609	10,195,454	9,710,204	9,710,204	16,880,066
DS - CNG	1,130,275	1,078,558	760,289	773,442	786,823
GTH - Hydrogen Blending	6,000,000	8,700,000	2,400,000	-	-
UTIL - Meters Growth	7,908,353	8,177,237	8,455,263	8,742,742	4,934,538
Total	90,313,200	99,289,392	92,859,037	91,159,750	93,531,770

EGD + OH

	31.62%	29.55%	37.09%	38.39%	43.58%
USP Categories	2024	2025	2026	2027	2028
Customer Connections	93,134,464	92,156,599	98,068,133	99,545,552	101,841,767
DP Relocations	5,943,541	13,207,800	13,312,147	13,437,543	24,236,394
DS - CNG	1,487,692	1,397,228	1,042,314	1,070,334	1,129,720
GTH - Hydrogen Blending	7,897,329	11,270,500	3,290,266	-	-
UTIL - Meters Growth	10,409,144	10,593,281	11,591,693	12,098,713	7,085,009
Total	118,872,170	128,625,408	127,304,554	126,152,141	134,292,889

EGI

USP Categories	2024	2025	2026	2027	2028
Customer Connections	111,795,662	111,746,480	111,950,294	112,295,799	110,639,335
DP Relocations	32,285,609	34,255,454	32,640,204	33,375,204	40,980,066
DS - CNG	2,663,978	1,078,558	760,289	773,442	786,823
GTH - Hydrogen Blending	7,450,000	8,700,000	2,400,000	-	-
TPS - Growth	5,433,461	58,122,323	102,936,935	162,585,344	
UTIL - Meters Growth	12,926,065	13,365,551	13,819,979	14,289,859	8,851,529
EA Fixed - Growth	38,243,358	39,210,708	40,214,787	41,257,638	23,218,092
Community Expansion	11,202,509	19,578,607	20,494,389	21,478,734	7,343,532
Total	222,000,642	286,057,681	325,216,876	386,056,020	191,819,377

EGI + OH

USP Categories	2024	2025	2026	2027	2028	Total
Customer Connections	146,275,450	144,354,305	152,984,388	154,499,827	158,772,395	756,886,365
DP Relocations	41,904,649	44,134,376	44,468,080	45,657,919	58,788,471	234,953,495
DS - CNG	3,473,780	1,397,228	1,042,314	1,070,334	1,129,720	8,113,376
GTH - Hydrogen Blending	9,775,024	11,270,500	3,290,266	-	-	24,335,790
TPS - Growth	7,036,128	74,710,075	139,864,638	221,363,238	179,983,040	622,957,119
UTIL - Meters Growth	16,906,893	17,262,308	18,880,953	19,651,225	12,700,784	85,402,162
EA Fixed - Growth	38,243,358	39,210,708	40,214,787	41,257,638	23,218,092	182,144,583
Community Expansion	11,202,509	19,578,607	20,494,389	21,478,734	7,343,532	80,097,771
Total	274,817,791	351,918,107	421,239,814	504,978,915	441,936,033	1,994,890,660

Table 1: 15-Year Revenue Horizon

$ Million	2024	2025	2026	2027	2028	Total
1) Customer Connections	146.3	144.4	153.0	154.5	158.8	756.9
2) DP Relocations	41.9	44.1	44.5	45.7	58.8	235.0
3) DS - CNG	3.5	1.4	1.0	1.1	1.1	8.1
4) GTH - Hydrogen Blending	9.8	11.3	3.3	-	-	24.3
5) TPS - Growth	7.0	74.7	139.9	221.4	180.0	623.0
6) UTIL - Meters Growth	16.9	17.3	18.9	19.7	12.7	85.4
7) EA Fixed - Growth	38.2	39.2	40.2	41.3	23.2	182.1
8) Community Expansion	11.2	19.6	20.5	21.5	7.3	80.1
9) Total	274.8	351.9	421.2	505.0	441.9	1,994.9

Direct Capital Cost Supportable by New Connections Revenue

10 year Rev Horizon	2024	2025	2026	2027	2028
EGD	45,662,014	45,906,706	46,161,695	46,419,875	45,772,609
Union South	17,455,839	17,323,327	17,303,972	17,327,794	17,091,059
Union North	4,124,136	4,032,085	3,951,702	3,899,843	3,793,531
Total	67,241,989	67,262,118	67,417,369	67,647,511	66,657,199

UG					
USP Categories	2024	2025	2026	2027	2028
Customer Connections	21,579,975	21,355,412	21,255,674	21,227,637	20,884,590
DP Relocations	27,770,000	24,060,000	22,930,000	23,665,000	24,100,000
DS - CNG	1,533,703	-	-	-	-
GTH - Hydrogen Blending	1,450,000	-	-	-	-
TPS - Growth	5,433,461	58,122,323	102,936,935	162,585,344	125,537,786
UTIL - Meters Growth	5,017,712	5,188,314	5,364,716	5,547,117	3,916,991
Total	62,784,850	108,726,049	152,487,325	213,025,098	174,439,367

UG + OH	30.79%	29.70%	37.70%	38.02%	43.37%
USP Categories	2024	2025	2026	2027	2028
Customer Connections	28,225,518	27,698,806	29,268,109	29,298,659	29,942,156
DP Relocations	36,321,758	31,206,762	31,573,581	32,662,740	34,552,077
DS - CNG	2,006,006	-	-	-	-
GTH - Hydrogen Blending	1,896,527	-	-	-	-
TPS - Growth	7,106,693	75,386,929	141,739,541	224,402,398	179,983,040
UTIL - Meters Growth	6,562,914	6,729,446	7,386,973	7,656,203	5,615,775
Total	82,119,416	141,021,944	209,968,205	294,019,999	250,093,047

EGD					
USP Categories	2024	2025	2026	2027	2028
Customer Connections	45,662,014	45,906,706	46,161,695	46,419,875	45,772,609
DP Relocations	4,515,609	10,195,454	9,710,204	9,710,204	16,880,066
DS - CNG	1,130,275	1,078,558	760,289	773,442	786,823
GTH - Hydrogen Blending	6,000,000	8,700,000	2,400,000	-	-
UTIL - Meters Growth	7,908,353	8,177,237	8,455,263	8,742,742	4,934,538
Total	65,216,252	74,057,955	67,487,451	65,646,263	68,374,036

EGD + OH	33.08%	30.80%	39.09%	40.57%	43.58%
USP Categories	2024	2025	2026	2027	2028
Customer Connections	60,765,084	60,046,148	64,204,203	65,252,924	65,720,299
DP Relocations	6,009,182	13,335,693	13,505,481	13,649,740	24,236,394
DS - CNG	1,504,123	1,410,758	1,057,451	1,087,236	1,129,720
GTH - Hydrogen Blending	7,984,547	11,379,634	3,338,051	-	-
UTIL - Meters Growth	10,524,103	10,695,857	11,760,041	12,289,768	7,085,009
Total	86,787,039	96,868,090	93,865,227	92,279,667	98,171,422

EGI					
USP Categories	2024	2025	2026	2027	2028
Customer Connections	67,241,989	67,262,118	67,417,369	67,647,511	66,657,199
DP Relocations	32,285,609	34,255,454	32,640,204	33,375,204	40,980,066
DS - CNG	2,663,978	1,078,558	760,289	773,442	786,823
GTH - Hydrogen Blending	7,450,000	8,700,000	2,400,000	-	-
TPS - Growth	5,433,461	58,122,323	102,936,935	162,585,344	
UTIL - Meters Growth	12,926,065	13,365,551	13,819,979	14,289,859	8,851,529
EA Fixed - Growth	38,243,358	39,210,708	40,214,787	41,257,638	23,218,092
Community Expansion	11,202,509	19,578,607	20,494,389	21,478,734	7,343,532
Total	177,446,969	241,573,319	280,683,952	341,407,733	147,837,240

EGI + OH						
USP Categories	2024	2025	2026	2027	2028	Total
Customer Connections	88,990,602	87,744,954	93,472,312	94,551,583	95,662,455	460,421,906
DP Relocations	42,330,941	44,542,455	45,079,062	46,312,479	58,788,471	237,053,408
DS - CNG	3,510,128	1,410,758	1,057,451	1,087,236	1,129,720	8,195,294
GTH - Hydrogen Blending	9,881,074	11,379,634	3,338,051	-	-	24,598,758
TPS - Growth	7,106,693	75,386,929	141,739,541	224,402,398	179,983,040	628,618,601
UTIL - Meters Growth	17,087,017	17,425,304	19,147,014	19,945,970	12,700,784	86,306,089
EA Fixed - Growth	38,243,358	39,210,708	40,214,787	41,257,638	23,218,092	182,144,583
Community Expansion	11,202,509	19,578,607	20,494,389	21,478,734	7,343,532	80,097,771
Total	218,352,322	296,679,350	364,542,608	449,036,039	378,826,092	1,707,436,410

Table 1: 10-Year Revenue Horizon

$ Million	2024	2025	2026	2027	2028	Total
1) Customer Connections	89.0	87.7	93.5	94.6	95.7	460.4
2) DP Relocations	42.3	44.5	45.1	46.3	58.8	237.1
3) DS - CNG	3.5	1.4	1.1	1.1	1.1	8.2
4) GTH - Hydrogen Blending	9.9	11.4	3.3	-	-	24.6
5) TPS - Growth	7.1	75.4	141.7	224.4	180.0	628.6
6) UTIL - Meters Growth	17.1	17.4	19.1	19.9	12.7	86.3
7) EA Fixed - Growth	38.2	39.2	40.2	41.3	23.2	182.1
8) Community Expansion	11.2	19.6	20.5	21.5	7.3	80.1
9) Total	218.4	296.7	364.5	449.0	378.8	1,707.4

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 190

Enbridge to advise on, if the board were to change the revenue horizon, what exactly would it track and what it is that it would attempt to capture.

Response:

Should the OEB reduce the revenue horizon used for determining customer attachment feasibility, Enbridge Gas has noted it may be appropriate to introduce a deferral or variance account. A deferral or variance account could address the uncertainty the Company has with regards to how customer behaviour would be impacted by a change to the revenue horizon and the associated impacts it would have on required contributions in aid of construction. A change in the revenue horizon could impact the level and/or mix of customer additions that would occur, which in turn could impact actual versus forecast capital requirements and revenues. As such, the deferral or variance account could potentially track variances in customer attachment costs and revenues relative to what is reflected in 2024 rates. A change to the revenue horizon, as described at Exhibit J10.13, would also result in implementation costs which could be tracked in a deferral or variance account.

At this time the Company is not certain how a potential deferral or variance account would be proposed to operate, as it would depend on the OEB's decision with respect to the appropriate revenue horizon, and any associated changes to the forecast 2024 revenue requirement that may or may not accompany a change (i.e. a capital reduction). As such, the need for and operation of a deferral or variance account will be assessed following the OEB's decision. The introduction of a deferral or variance account, and associated accounting order, could be facilitated through the Draft Rate Order process for Phase 1, or through a subsequent phase of the Application. The Company also notes that there may be additional considerations related to the need or operation of an account in years in which a price cap mechanism is in place.

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking

Tr: 202

Enbridge will advise as to its position on the time it would need, or would request, to implement a new revenue horizon policy if that was directed by the OEB.

Response:

In the event that the OEB directs Enbridge Gas to adopt a new revenue horizon as part of its customer attachment feasibility policy, the Company will require lead-time for implementation. As explained below, depending on the level of change directed by the OEB, Enbridge Gas believes that it may be able to implement at least some aspects of an updated customer attachment policy as of January 1, 2025. Other aspects, such as a yet-to-be approved alternate approach for infill customers and changes that could impact the Ontario Government mandated Natural Gas Expansion Program may take longer to implement. Enbridge Gas submits that customers who have requested service in writing, received commitments and/or indications about CIAC requirements (or lack thereof) for new connections prior to that date should be subject to the existing rules even if the connection is not completed until after January 1, 2025 (or such later date as the new policies come into effect).

Customer Connections Process

Enbridge Gas deals with approximately 3,000 applications to connect a month. Broadly speaking, the expected impacts that Enbridge Gas foresees from changes to the revenue horizon included in the customer connection policy can be classified into four main categories: customer facing, systems changes, operational changes and regulatory implications. Each of these categories is discussed below.

Customer Facing Impacts

- Market communication of change - This may include provision of notices to other parties including the Government of Ontario, specifically, the Ministry of Energy (MOE) and the Ministry of Economic Development Job Creation & Trade and municipal governments.

- Customer engagement, communication and education based on new feasibility guidelines.
- Communication and rollout of changes noted below to the GetConnected system, which provides the market interface for managing connections and reflects approved policies.[1]
- Training for market participants including builders and HVAC companies, currently estimated at 7000, who are the primary interface with conversion (infill) and community expansion customers and typically apply for service on their behalf.

System Changes Impacts

- IT changes to feasibility tools - These changes vary from minor edits to Excel based models to large scale system updates. The online feasibility tool used by the Operations team is currently designed for a 40-year revenue horizon. Shortening the revenue horizon will require new coding which will trigger an IT change project and require engagement of internal and external IT experts to make that change.
- IT changes to Enbridge Gas's application (GetConnected) and work management systems (CCWS) – These changes will vary based on the magnitude of the change to the revenue horizon. These systems support applications for natural gas service and hold automatic communication tools that would all have to be updated with new policy and cost information.
- Enbridge Gas website system changes will be required to inform customers about access to natural gas in their area, new business policies and the process to obtain a natural gas service, and community expansion information.
- Customers may also require a payment plan for financing an up-front connection payment, which is not supported by the current billing system and would require a significant system change.

Operational Changes Impacts

- Significant changes to Customer Connections business processes as well as updates to a number of the Company's internal policies, processes, procedures and customer communication documents.
- Training for Operations and Call Centre employees which include Customer Connections reps, regional new business field representatives, construction teams, and Call Centre Reps (CSRs). These resources would need extensive training regarding new policies and how they would be applied to qualifying customers. The Company would need to be prepared for an increase in call

[1] Land developers or home builders typically initiate the customer attachment process with Enbridge Gas through the online GetConnected tool.

volume and be able to answer challenging questions on new policies and cost escalations.

- A reassessment of resource requirements to support these changes based on the expectation of an increased number of activities related to cost estimation for infill projects, CIAC collections, customer inquiries and escalated complaints. Given the changes, there may be resource constraints that will impact the processing of customer requests and potentially delay service connections. This could lead to an escalation in the number of customer complaints.
- Additional resources may also be needed to respond to increased inquiries from the OEB compliance office, who can be expected to receive significant amounts of inquiries and complaints in response to higher connection costs.
- The Company will need to implement a process to review impacts to existing and proposed new business policies including the Extra Length Charge (ELC) to evaluate if an updated free service allowance and per metre charge or another equivalent may be workable. The options that the Company might consider are detailed at Exhibit J10.7. As part of this process the Company would engage with customers to assess market preferences for these options.

Regulatory Implications

- Additionally, a different revenue horizon would require a different ELC or equivalent. Enbridge Gas would have to determine the appropriate approach, and then apply to the OEB for approval.
- Also, changes would likely be required for the SES and TCS, such that the maximum revenue horizon should be no greater than new revenue horizon if changed. This would also require OEB review and approval.
- Changes to the revenue horizon would only be applied to new service requests received after the date of implementation.
- As noted, it can be expected that there will be secondary impacts to OEB in terms of customer complaints and inquiries to the OEB compliance office. The magnitude of such impact can be seen by the fact that Enbridge Gas deals with approximately 3,000 applications to connect a month.

Separate from (or additional to) the items noted above, Community Expansion represents an implementation challenge as these projects were proposed by the Company, reviewed by the OEB and approved by the MOE via legislation and regulations that enable the necessary funding mechanisms. At this time several (9) projects are complete, 19 are in execution and 3 are pending LTC filing.[2] These projects were evaluated in accordance with existing policies and rules and premised on customer surveys and economic evaluations. In addition, Enbridge Gas is exposed to risk during the 10-year Rate Stability Period. To allow these projects to proceed and maintain a level playing field, the revenue horizon and current OEB-approved SES

[2] Exhibit JT5.25

policies would need to be maintained for ongoing Community Expansion projects. Alternatively, the MOE could choose to amend the legislation to increase the funding to the extent required to allow these projects to be financially neutral.

Planned Implementation Timing

Should the OEB order a change to the E.B.O.188 Guidelines Enbridge Gas would need to review the decision and assess the full range of impacts to its business operations and develop an implementation plan, however the Company expects that implementation can be achieved in around 12 months. This would include time to have proper communication to the market about the upcoming changes.

Considering all of the implementation impacts as described above, Enbridge Gas believes (though this may be optimistic) that an implementation date of January 1, 2025, would likely be appropriate. This timing would allow Enbridge Gas to consider the extent of the impacts stemming from an OEB decision, prepare and file an updated connection policy and other related evidence, complete the regulatory approval process for a new ELC or fixed CIAC for infill customers, as well as updated SES and TCS, and implement all necessary business process and system changes. Should Enbridge Gas require a later implementation date, it would make a request to the OEB.

Enbridge Gas proposes that implementation of a new customer attachment policy should apply on a prospective basis only, for any new customers who approach the Company with a new connection request from and after January 1, 2025 (or such later implementation date that is approved). Any changes to the feasibility calculation would need to remain consistent for customers and in accordance with the approved guidelines from the time when service was originally requested with a planned cutover at the time of implementation.

Customers who have requested service in writing, received commitments and/or indications about CIAC requirements (or lack thereof) for new connections prior to that date should be subject to the existing rules even if the connection is not completed until after January 1, 2025 (or such later date as the new policies come into effect).

Connection requests are executed in some cases within 2-3 months of feasibility analysis but in other cases projects can take up to 2-3 years where an extensive development/subdivision or LTC application is involved. Enbridge Gas believes in the fair and equitable treatment of customers and that customers should have the connection policy under which they requested service applied to their projects regardless of execution status. Customers should be treated in a manner that considers the circumstances of each connection project which may be at varying degrees of development, acceptance or execution at January 1, 2025.

Builders and developers have sold homes and condominiums based on an understanding of their costs to connect to the distribution system through discussions with Enbridge Gas. Businesses including design build companies also operate on similar assumptions and rely on Enbridge Gas's offer to connect in the establishment of equipment selection and ultimately pricing. The same is true of infill customers. It would not be appropriate or fair to change the rules for committed customers and require a new or increased CIAC.

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking

Tr: 10

RE Exhibit K10.3, Page 7: Enbridge Gas to provide the 20-year figures for the various revenue horizons.

Response:

Please see the updated Table 1 after incorporating 20-year revenue horizon. Please also note the table includes the corrections noted in Exhibit J10.11.

Table 1
Customer Connections Capital Expenditure Supported by Different Revenue Horizons

Line No.	Revenue Horizon	2024	2025	2026	2027	2028	Total	Reduction vs. 40 Year Revenue Horizon	CIAC per Customer	
	(Years)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)		
1	40	304	248	258	254	250	1,314			
2	30	229	227	239	241	253	1,190	124	645	/u
3	25	210	208	219	221	235	1,094	220	1,140	/u
4	20	188	185	196	198	205	972	342	1,774	
5	15	146	144	153	154	159	757	557	2,890	
6	10	89	88	93	95	96	460	853	4,428	

Note: 40-year revenue horizon reflects the Company's most updated capital forecast

ENBRIDGE GAS INC.

Answer to Undertaking from
Green Energy Coalition (GEC)

Undertaking

Tr: 31

Enbridge to advise as to the reasons for the differences in the 15-year scenario in ADR.4 and Table 1 of the EGI examination in chief for the customer connections panel and further, to advise which of those numbers represents the difference that the OEB should consider in terms of capital expenditure requirements, if the revenue horizon was reduced to 15 years.

Response:

The variance of $557 million for the 15-year scenario from page 139 of Exhibit K10.2 represents the difference between the Customer Connections spend category only. This includes direct capital spend net of Customer Contributions in Aid of Construction (CIAC) plus an allocation of capitalized overheads associated with new customer connections:

40-year horizon forecast (a) = $1,314 million
15-year horizon forecast (b) = $757 million
Variance (a-b) = $557 million

The variance in Exhibit I.ADR.4 of $485 million represents the total difference in spend for the System Access Utility System Plan category under a 15-year revenue horizon scenario. The total System Access spend as shown in Exhibit I.ADR.6 is $2,480 million. Please see Table 1 below for the total System Access spend applying a 15-year revenue horizon scenario. Please note that System Access spend includes a total of all investment categories in Table 1 (below) including customer connections.

System Access - 40-year horizon forecast (a) = $2,480 million
System Access - 15-year horizon forecast (b) = $1,995 million
Variance (a-b) = $485 million

Note the variance for total System Access of $485 million is lower than the Customer Connections variance of $557 million due to the reallocation of capitalized overheads to

the other categories of spend. Capitalized overheads are allocated to projects based on the percentage of total overhead and total direct capital spend. Therefore, as the amount of direct capital decreases, the percentage of overhead allocated will increase.

The expected reduction in spending, based on the simplified scenarios of adjusting the revenue horizon to 15 years, is $485 million. This reduction in spend would be recovered from all new customers through CIAC, assuming these customers all still connect to the system. Note that Enbridge Gas does not support a 15-year revenue horizon as being appropriate to apply to Community Expansion projects.

Table 1

$ Million	2024	2025	2026	2027	2028	Total
1) Customer Connections	146.3	144.4	153.0	154.5	158.8	756.9
2) DP Relocations	41.9	44.1	44.5	45.7	58.8	235.0
3) DS - CNG	3.5	1.4	1.0	1.1	1.1	8.1
4) GTH - Hydrogen Blending	9.8	11.3	3.3	-	-	24.3
5) TPS - Growth	7.0	74.7	139.9	221.4	180.0	623.0
6) UTIL - Meters Growth	16.9	17.3	18.9	19.7	12.7	85.4
7) EA Fixed - Growth	38.2	39.2	40.2	41.3	23.2	182.1
8) Community Expansion	11.2	19.6	20.5	21.5	7.3	80.1
9) Total	274.8	351.9	421.2	505.0	441.9	1,994.9

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 71

Enbridge to advise as to how the customer contribution was determined for the Ridge Landfill site, an injection customer, and whether Enbridge holds any security, or any future protection, from the customer.

Response:

As stated in EB-2022-0203, Tab 1, Schedule 1, page 3, paragraph 3:

> The Customer has contracted with Enbridge Gas under Rate M13-Union South Transportation of Locally Produced Gas. The executed contract between Enbridge Gas and the Customer is included as Attachment 1 to this Exhibit. The Customer has elected to pay the full capital cost of the Project through an upfront CIAC payment, resulting in a net investment of $0.0 million. Consequently, a Net Present Value or Profitability Index calculation is not required for the Project.

As is stated in the M13 General Terms and Conditions, when a customer elects to pay the full capital cost of the project upfront, 50% of the payment is required at contract execution and the final 50% is due prior to installation of the meter station. If actual capital costs vary from the estimate that was used for determining the upfront payments, a true-up is calculated after all construction has finished and a payment to/from the customer is determined.

Enbridge Gas holds security in the form of a letter of credit in the amount of $120,000.

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 76

Enbridge to file the IESO's pathways to decarbonization study.

Response:

In order to be responsive to this undertaking, please see Attachment 1 for the IESO Pathways to Decarbonization Study.

However, having reviewed Tr. Vol.11 74 to 76, Enbridge Gas believes the study being requested is work conducted by NREL (National Renewable Energy Laboratory) in collaboration with Xcel Energy to evaluate heat pump technology at a thermal test facility in Colorado.

Enbridge Gas reached out to Xcel Energy to access a copy of the study and was advised that the report is not yet fully public and a date at which it will be available has not been provided. However, provided at Attachment 2 is the article “Heat Pump performs below par at high altitude, in really cold weather, Xcel, NREL study shows” (July 24, 2023) by Scott Weiser from the Denver Gazette that references the study. This was the article to which Ms. Giridhar was referring in her testimony.

Enbridge Gas also reached out to NREL, since they were part of the work referenced by Ms. Giridhar. In response, Enbridge Gas was advised that a similar recent study was completed in 2022 entitled “Performance Assessment of High Efficiency Variable Speed Air-Source Heat Pump in Cold Climate Applications”, provided at Attachment 3. This study shows that the rated performance and heating capacity of high efficiency air-source heat pumps drop as the outdoor air temperature drops and in fact, the derating fractions decrease the rated performance even further. See pages 31-33.

Pathways to Decarbonization

A report to the Minister of Energy to evaluate a moratorium on new natural gas generation in Ontario and to develop a pathway to zero emissions in the electricity sector.

DECEMBER 15, 2022

PUBLIC

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Powering Tomorrow.

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This report is provided for informational purposes only. The IESO has prepared this report based on currently available information and on assumptions about the future availability of electricity supply and demand growth. The information, statements and conclusions in this report are subject to risks, uncertainties and other factors that could cause actual results or circumstances to differ materially from the report's findings. The IESO provides no guarantee, representation, or warranty, express or implied, with respect to any statement or information in this report and disclaims any liability in connection with it.

Executive Summary

While Ontario benefits from one of the cleanest electricity systems in North America (which contributes only three per cent of the province's total greenhouse gas emissions), the process of eliminating all emissions from the grid is a significant and complex undertaking that will require an extensive and collaborative effort to achieve.

The Pathways to Decarbonization report explores this effort, responding to the Minister of Energy's request to evaluate a moratorium on new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system.

Two scenarios – Moratorium and Pathways – are presented to address the Minister's request. These scenarios are not integrated power system plans. Rather, they are analyses that identify potential opportunities and challenges to consider, particularly as demand for electricity grows and Ontario's resource mix evolves. The Independent Electricity System Operator (IESO) brings the expertise and experience of the system operator to this study, and as such, the results contribute future-looking insights that can inform policy and strategy development. They make it clear that a carefully governed and orderly approach to the energy transition will be necessary to maintain reliability and manage costs.

One key insight of this analysis is that phasing gas generation out of the system will require ingenuity and the implementation of new technologies to reorient our current system, which is grounded in the flexibility that natural gas generators provide. This is in part because Ontario's natural gas fleet is capable of providing continuous, flexible energy year round and under all weather conditions, and there is currently no like-for-like replacement. This means natural gas will be needed until reliable replacements have been identified, put into service and have demonstrated their capability.

Another key takeaway is that in an environment of rapid economic growth and electrification, where demand for electricity will increase at unprecedented rates, a significant investment in new electricity system infrastructure in a relatively short period will be essential to meeting emissions reductions targets.

Understanding these issues provides a foundation for action and contributes to the ongoing conversation about the energy transition. As such, this report will inform the work of the Ontario government's Electrification and Energy Transition Panel (EETP) and the Cost-Effective Energy Pathways Study[1].

Moratorium on Natural Gas Generation

On the question of when a moratorium on new natural gas generation facilities can begin, the IESO looked at what resources would be needed to ensure reliability mid-decade and then after 2027. Against a backdrop of growing demand and increasing pressure on supply, we assessed the potential for capacity, energy and transmission expansion without additional natural gas generation after the IESO's current long-term procurement for new supply.

This assessment showed that a moratorium would be feasible beginning in 2027. At that point, the system would not require additional emitting generation to ensure reliability, provided that other forms of non-emitting supply can be added to the system in time to keep pace with demand growth. The results of this scenario would require investments of approximately $26 billion in new infrastructure.

The Moratorium scenario also shows that once the current slate of nuclear refurbishments is completed and new non-emitting supply enters the system, emissions could begin to decrease significantly. In this scenario, 4,000 megawatts (MW) of natural gas generation is retired and emissions drop by 60 per cent. Natural gas generation would, however, be needed to continue to provide flexibility to the broader system and meet local needs in the Greater Toronto Area (GTA) – an issue that the IESO is actively evaluating further.

A Pathway to Decarbonization

In the development of a pathway to a decarbonized grid, the IESO adopted a more aggressive electrification demand forecast. The Pathways scenario illustrates a system designed to meet winter peaks that are almost three times higher than those we experience today. As a result, the system would likely require an additional 69,000 MW of non-emitting supply and 5,000 MW in demand reductions from conservation.

We therefore contemplated a decarbonized supply mix by 2050 with contributions from new nuclear, conservation, demand response, renewables and storage. The mix also includes low-carbon generation such as hydrogen and renewable natural gas – currently emerging technologies – at scale. The need for a significant increase in transmission capability was also identified.

[1] To inform the work of the EETP, the Ministry of Energy is undertaking a study to understand pathways for economy-wide decarbonization. The work will begin in December 2022.

Decarbonizing Ontario's Electricity System

Bridging the work of today with the needs of a decarbonized world will be challenging and complex. Ontario's electricity system is well positioned to make the transition, but will need to address a series of challenges in order to achieve decarbonization.

System Capacity Today

42,000 MW

MANAGE COSTS

$400 billion over 2.5 decades

PREPARE FOR SITING AND LAND USE

Siting requirements **14 times** the size of Toronto

FOCUS ON INDIGENOUS PARTNERSHIPS

Increased role beyond current **20%** participation rate in electricity projects

DEVELOP CAPITAL/LABOUR RESOURCES

A potential **six-fold increase** in existing workforce to build projects

FOCUS ON INNOVATION

New technologies to drive new supply such as **15,000 MW** of hydrogen capacity

INCREASE POLICY CERTAINTY

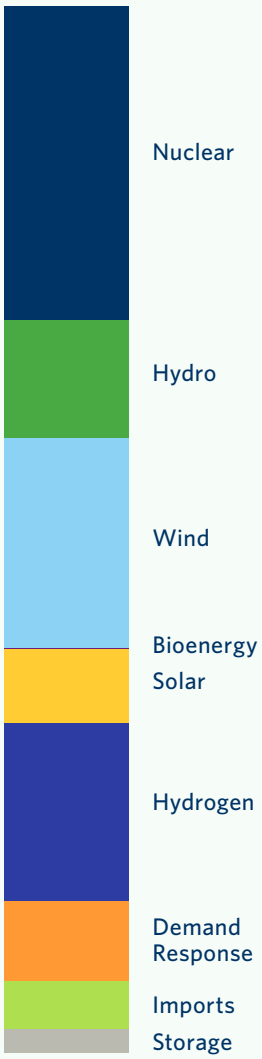
Near and long-term certainty to drive **private sector investment** in infrastructure and technology

STREAMLINE REGULATORY PROCESSES

Streamlined siting and regulatory processes keeping the **local perspective** at the core

Pathways to Decarbonization 2050 Scenario

88,000 MW



In all, the bulk system expansion needed to enable decarbonization in this scenario would require an investment in the range of $375 to $425 billion.

Both the Moratorium and Pathway scenarios demonstrate that it is possible to reliably manage the energy transition with the necessary investments, and they highlight the time, cost and risks involved. How Ontario's new supply mix actually evolves will depend on future research, analysis, consumer preferences and, ultimately, policy and investment decisions. More research and planning work will be needed to turn these scenarios into an actionable plan to move Ontario's current clean supply mix and system toward a fully decarbonized target.

Addressing Risks

Bridging the work of today with the needs of a decarbonized world will be challenging and complex. While Ontario has a very clean electricity grid today, it must still be prepared to address dependencies that are key to meeting broader decarbonization goals:

- Large infrastructure such as hydroelectric, nuclear facilities and transmission can take 10 to 15 years to build. Preliminary work should begin now so that options are available in the 2030s and beyond.
- Significant investments in capital, materials and labour will be required to build out a fully decarbonized system. One study[2] estimates that the 14,000-strong labour force currently working on electricity infrastructure projects could need to increase six-fold for decades.
- Communities and First Nations across the province have a growing voice in how and where new infrastructure is located, so meaningful and transparent discussions about siting and land use will be required.
- While many of the technologies needed to decarbonize are already known and commercialized, many others, including low-carbon fuels and small modular reactors (SMRs), are still in development. It will be important for Ontario and Canada to continue to invest in these, and other, innovations.
- Energy plans need to be approved and new infrastructure needs to be planned, permitted and sited. Regulatory and approval processes, such as environmental and impact assessments, need to be resourced appropriately and streamlined to enable this.
- Costs must be carefully managed to ensure the actual impact on total energy costs is affordable and that they do not diverge significantly from those of our neighbours. Rapidly rising electricity costs could discourage electrification, stifle economic growth or hurt consumers with low incomes.

[2] See Appendix B, section 6

Conclusions

This report demonstrates the sheer scope and magnitude of the effort needed should Ontario decide to decarbonize its electricity system while achieving a net-zero economy by 2050. The IESO has identified a number of "no regret" actions that can be taken to help meet growing demand, address retirements of existing generation and ensure a state of readiness to manage any future decarbonization policy. These actions will lay the groundwork that both builds on Ontario's already clean system and allows for progress in a shifting environment. These no regrets actions include:

- Accelerating current efforts to acquire new non-emitting supply, including the implementation of recent conservation and demand management directives.
- Beginning the planning, siting and environmental assessment work needed for new nuclear, long-duration storage and hydroelectric facilities, as well as transmission infrastructure, to allow for faster implementation.
- Investing in emerging technologies like low-carbon fuels. Further work is needed to determine if they can replace at scale some of the flexibility that natural gas currently provides the system.
- Galvanizing collaboration amongst stakeholders and Indigenous communities.
- Ensuring that regulatory, approval and permitting processes are ready to manage future investment at scale.
- Establishing an open, transparent and traceable process to measure progress and demonstrate the results of decisions and actions taken along the way.

For its part, the IESO will incorporate the many learnings from this report into its core work, including more explicitly addressing the risks of climate change and the ongoing energy transition in its planning and procurement processes.

Introduction

In Canada, as in many countries around the world, governments are developing policies aimed at achieving their own net-zero greenhouse gas (GHG) emissions economies by 2050, supported by clean electricity systems. In Ontario, the government is taking action by establishing the upcoming Cost-Effective Energy Pathways Study, as well as launching a climate change impact assessment, investing in innovative SMRs, and implementing one of the largest battery storage procurements ever undertaken. At the federal level, the government recently proposed the Clean Electricity Regulations (CER) and complementary policies to decarbonize Canada's electricity system by 2035.

At the local level, customers are also driving this transition. A movement toward environmental, social and corporate governance goals is encouraging the growth and development of non-emitting electricity resources. Businesses and homeowners are exploring how to shift away from fossil fuel-based energy for building heating, transportation, and industrial processes, among others, and they are expecting a clean electricity supply to power the transformation.

Today Ontario's electricity system is already more than 90 per cent emissions-free and the sector contributes only three per cent to the province's total greenhouse gas emissions. However, as the broader economy decarbonizes, there will be increased pressure on the grid to meet significant growth in demand for electricity.

In recognition of these trends and in response to the IESO's 2021 technical study on the phase-out of natural gas, the Minister of Energy directed the IESO to explore the feasibility of a moratorium on new gas-fired electricity generation and a pathway to a decarbonized electricity system. The Minister asked the IESO to consider reliability and cost in the analysis, and to explore low-carbon fuels and carbon capture and storage. He also asked that the report examine the role of technologies such as pumped storage and battery storage combined with non-emitting resources, as well as hydroelectric, nuclear and demand response.

In response to the Minister's request, the IESO undertook a scenario assessment exercise informed by stakeholder engagement and outreach. While not an integrated electricity system planning process, these scenarios were developed using the same tools and methodologies, and provide valuable insights into the work required to achieve this goal.

Given our mandate, this assessment focuses only on the bulk power system – i.e., high-voltage transmission lines, generation and interconnections with neighbouring jurisdictions – and does not consider the impact on local distribution systems. We expect, however, that some of the resources identified in this study will be distributed energy resources (DERs) connected within the distribution system. In developing a zero-carbon, reliable scenario and as requested by the Minister, we have used cost as a key determining factor. Our assessments, therefore result in cost-optimized supply mixes.

Consistent with many other recent studies, this report shows that achieving a net-zero economy powered by an emissions-free electricity system will involve a massive investment in new infrastructure and increased cost. It also notes that significant risks and dependencies will have to be addressed to enable implementation. It will be vital that this transition is managed prudently so that costs do not discourage electrification, negatively affect the economy, or place an undue burden on people with low incomes.

The characteristics of the scenarios presented in this report are based on current information – many other factors can, and likely will, influence what mix is ultimately put in place. These include: competition; the availability of resources, capital and labour; the impact of changing weather; the adoption rate of distribution-level resources; the level of community approval of new electricity projects; the pace of regulatory approvals; and the evolution and commercialization of certain markets and technologies, such as hydrogen, renewable natural gas and nuclear.

Climate Risk

The International Panel on Climate Change has called on nations around the world to reduce emissions by 2050 to limit temperature increases to 1.5 degrees Celsius thereby limiting the risks to natural and human systems.

Because of the accelerating effects of climate change, weather scientists forecast that Ontario's weather patterns will change significantly over the coming decades. These changes, which are well documented in the Climate Atlas of Canada, will have a major impact on how demand increases and decreases throughout the day, affecting the performance of the electricity system and the integrity of our infrastructure. If these issues are left unaddressed, there is a deepening concern that costs to the Canadian economy from weather and climate impacts will be significant, as reflected in a recent report from the Canadian Climate Institute.

It is clear that we will need to continually assess, understand, mitigate and adapt to changing weather.

Electricity System Reliability and the IESO's Role

Much of the activity of our daily lives depends on an electricity system that is reliable, meaning power is there when we need it to be. Ontario's electricity grid is one of the most reliable in the world, safely and steadily meeting the needs of the province every minute of every day. And because it works so seamlessly, its complex mechanisms are hidden – so much so that most of us only notice our electricity supply when it's not there.

In fact, our provincial grid is an extensive, dynamic and interconnected system that is both stable and nimble, with a foundation of reliable infrastructure that can respond to large and small changes whenever needed.

For the operators of this system to manage events as they occur in real time, in both normal and unexpected circumstances, many things are required: the system must meet the physical requirements of moving power along transmission and distribution lines, for example, as well as operating standards for reliability and security. It must also be able to respond to sudden changes quickly, and meet demand every hour of every day.

These responsibilities are top of mind today as a growing global momentum is driving the decarbonization of electricity systems in the pursuit of a net-zero economy. Thoughtful and detailed work has been undertaken recently in many jurisdictions, including in Canada, to explore the possibilities and timelines for moving electricity systems to non-emitting technologies.

All of these studies identify electrification as a viable option to mitigate the risk of climate change, and predict a massive build-out of electricity infrastructure. Appendix A, Tab 7 provides a high-level comparison of the IESO's results with similar studies produced by government, research institutes, regulators, and environmental organizations.

From the IESO's perspective, all of these efforts are a welcome contribution and add valuable insight to the collective understanding of what will be needed in the near and longer term. Most, however, use a relatively high-level lens, building potential supply mixes to meet only forecasted capacity and energy needs.

As the system operator and planner, we examined capacity and energy, but also factored in the requirements of the transmission system and began to consider the complexities of operating the electricity system as a whole on a day-to-day basis; this makes our contribution distinctive.

What we learned is that decarbonizing the electricity system is a complex task that must be carefully managed so as to not disrupt daily lives and the province's economy. In the modelling approach section that follows, the steps taken to develop reliable and cost-effective scenarios are described in detail.

> "Scenarios are not intended to represent a full description of the future. They highlight central elements of a possible future and draw attention to the key factors that will drive future developments. Scenarios are hypothetical constructs, not forecasts, predictions or sensitivity analysis."
>
> **Task Force on Climate-Related Financial Disclosure**

Modelling Approach

The Pathways to Decarbonization report complements the IESO's Annual Planning Outlook (APO), which accounts for demand and supply forecasts based on existing policy and project commitments, customer behaviour and available technologies. This report explores the possibilities for different patterns of consumption, broad electrification and the emergence of new technologies, as well as the expansion of the current supply mix over different time frames.

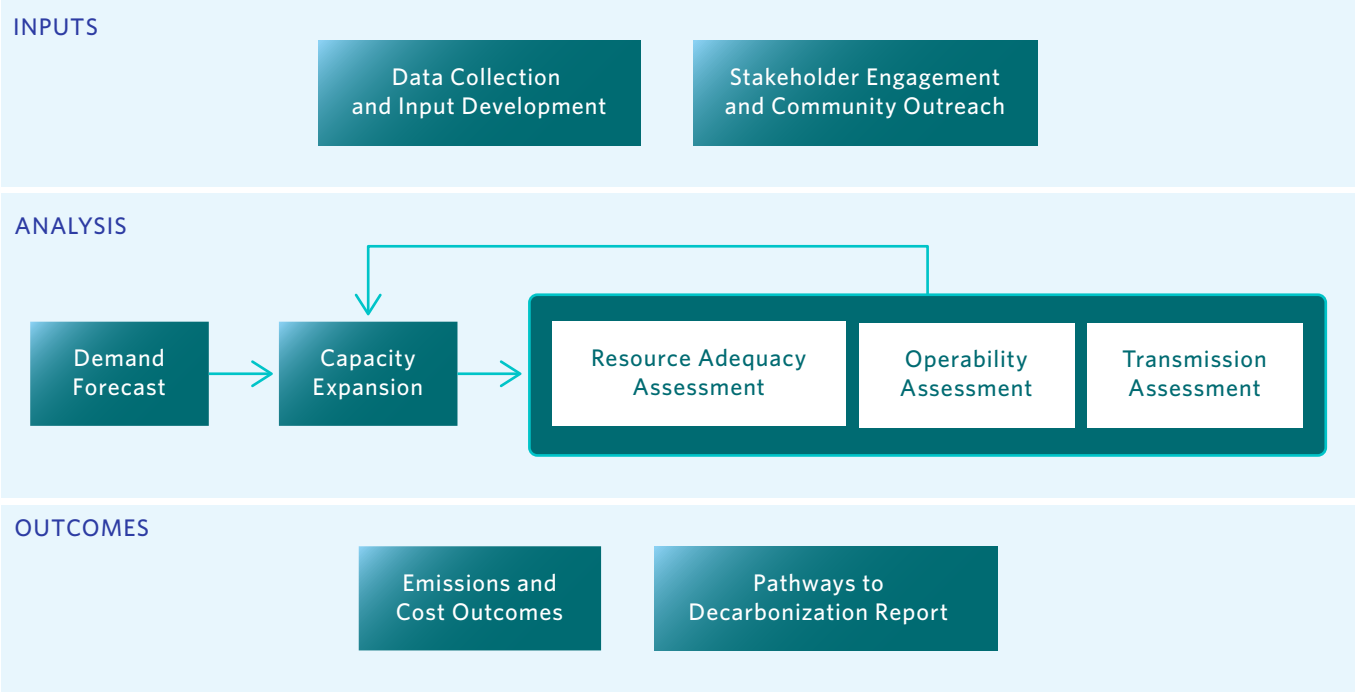
The two scenarios outlined in this report – Moratorium and Pathways – use software modelling tools, professional judgment and the set of detailed assumptions described below to simulate an energy-adequate expanded resource mix over a given time frame. The IESO created a mix based on the feasibility of new resources which accounted for build time and annual build limits, cost and performance. Only low-emissions resources that are considered technically feasible today, or that could be available within the time frame of the study, were included as potential new candidates for the future mixes.

It should be noted that reliability assessments were only performed for the final year of each scenario: 2035 for Moratorium and 2050 for Pathways. A thorough and detailed planning process would be required to identify reliable options for reaching these end-points. These plans typically take a number of years and incorporate many interdependent factors, such as facility commissioning and retirements, project planning, outages and much more.

Although this report is not a plan, it relies on the same data and expertise that the IESO uses in annual demand, resource and adequacy assessments. Technical standards that underpin the safe operation of electricity systems across the continent have been employed to highlight what a hypothetical future could look like if certain conditions were met.

The supply mix modelling and analysis process comprises a number of steps (see Figure 1), which are described in this section. The goal of this process is to develop a mix that is adequate, flexible, sustainable and diverse to ensure that the system is reliable in changing conditions.

Figure 1 | Supply mix modelling and analysis process steps



Scenario and Assumption Development

This report examines two questions: First, is a moratorium on natural gas generation possible in Ontario's electricity sector? Second, when and how can the sector be decarbonized? In response to these questions, two approaches were taken:

1. The **Moratorium** scenario, which focuses on 2035, examines whether a moratorium on the acquisition of new natural gas generation is feasible after the IESO's 2022/2023 resource procurements. (A moratorium on new gas within current resource procurements was found to be not feasible, as set out in the Resource Eligibility Interim Report.)
2. The **Pathways** scenario, which focuses on 2050, explores the time frame within which Ontario's electricity system could be **decarbonized**. In keeping with the assumptions of many other studies and to create an instructive "bookend" case to consider, this scenario assumes the decarbonization of the broader economy, which results in a significantly higher projection for demand based on substantial electrification within other sectors.

Beginning with its own information, including records for historical capacity and weather data, IESO planners compiled a list of technical assumptions for existing and emerging resources and government policy direction. They built on these assumptions using data and projections from the U.S. National Renewable Energy Lab Annual Technology Baseline – the most comprehensive and reliable information publicly available for a number of elements – as well as other sources. Policy and demand assumptions were compiled from internal research.

Stakeholders and communities also played a valuable role in shaping the assumptions used in the analysis. A formal IESO engagement with extensive outreach to sector participants was undertaken on the Pathways to Decarbonization effort between February and May to build awareness and seek input to inform the development of achievable pathways to decarbonization in Ontario's electricity sector.

Two webinars were held as part of the formal engagement initiative to provide an overview of the study approach, transparency around the modelling and analysis, and to seek technical feedback. Approximately 320 attendees participated in these sessions and more than 50 feedback submissions were received on preliminary assumptions posted for input. All meeting materials, assumptions, feedback received and IESO responses are posted on the engagement web page.

In addition, the IESO conducted extensive outreach with key communities and stakeholders to discuss this work and solicit input at a more granular level on technical assumptions, data sources, and data gaps. Over 30 meetings were held that encompassed more than 70 organizations and representatives of municipalities, generators, commercial and industrial customers, local distribution companies, environmental/sustainability organizations, Indigenous communities, sector associations, research and academia and energy consultants. This work has also been significantly informed by the expertise and advice received from the IESO's Stakeholder Advisory Committee members.

The IESO incorporated evidence-based feedback and input received in a number of areas, including in the assumptions related to policy, electricity demand, resource and technology.

The final assumptions can be found in Appendix A, Tab 1-3. A summary of key assumptions is included in Table 1. In order to be feasible, all modelling exercises involve a measure of simplification; Table 2 outlines some of these simplifications and considerations.

TABLE 1: OVERVIEW OF SCENARIO ASSUMPTIONS

Assumption Category	Moratorium	Pathways
Modelling Year	**2035**	**2050**
Carbon price (CO_2e; carbon dioxide equivalents)	$50/tonne in 2022, rising annually by $15/tonne and reaching $170/tonne by 2030.	Continues rising by $15/tonne from 2030-2035, and thereafter increases with the rate of inflation.
Emissions performance standard	As in the 2021 APO	370 tonnes (t) CO_2e/GW (gigawatt-hour) until and including 2030, dropping 74 tCO_2e/GWh per year to reach zero in 2035
Demand forecast (see Appendix A, Tab 2)	As in the 2021 APO	High-electrification forecast
Energy efficiency	Both scenarios assume the maximum level of demand reduction based on the cost-effective conservation and demand management (CDM) potential that was identified in the 2019 Achievable Potential Study	
Non-emitting resources (see Appendix A, Tab 3)	Wind[3], solar, hydroelectric, nuclear (includes large facilities and SMRs), demand response, storage, bioenergy and firm imports from clean jurisdictions	Same as Moratorium scenario, and low-carbon fuel was assumed to be available after 2035
Existing natural gas	Available for re-contracting after contract end if less than 25 years old	Before 2035, same as Moratorium. After 2035, retired at end of contract, but considered available for reliability until 25 years of age.

[3] Offshore wind was assumed to be available for development in the Pathways scenario, even though the IESO acknowledges the current moratorium on the technology.

TABLE 2: MODELLING CONSIDERATIONS

Factor	How Incorporated in the Report
Weather patterns	Historical normal weather patterns were used for this report. The IESO did not perform sensitivities to assess the impact of changing weather on normal demand.
Low-carbon hydrogen manufacture	In this report the IESO has assumed that hydrogen is produced outside of Ontario and therefore has no impact on demand. Producing hydrogen at scale within the province is expected to increase demand and the need for resources (see Enbridge's Pathways to Net-Zero Emissions In Ontario), although further work is needed to better understand the impacts of hydrogen production and deployment on the electricity system. The IESO will consider these impacts in future scenarios.
Carbon capture, utilization and storage (CCUS)	Based on feedback from stakeholders, CCUS was determined to be ill-suited to peaking applications, which is the forecasted role for the continued use of emitting supply, and was therefore not available as a resources option.
Distribution system	This study focused solely on the transmission-connected grid, and no analysis was conducted on the impact to distributions systems.
Emissions removal, including direct air capture	Emissions removal, including direct air capture, was not considered, as the Minister's request was for a zero-emissions grid.
Wind	Onshore wind was capped at 15,800 MW, limited by site quality, regulatory requirements and distance to transmission infrastructure.
Low-carbon fuels	Imported blue hydroelectric combusted in a new single-cycle turbine was used as a proxy for low-carbon fuels and was assumed to be available after 2035. Low-carbon fuels include pink, green and blue hydrogen, synthetic methane, renewable natural gas and biofuels, which can all be combusted in a turbine or used in a fuel cell. (For a discussion of some of the challenges facing low-carbon fuels see Appendix A, Tab 9.)
Storage	Batteries and pumped hydroelectric storage were used as proxies for storage more generally. The IESO recognizes that other types of storage could play a role in a decarbonized future. (See Appendix B, section 4 for a description of various different types of storage.)
Firm imports	External research (see Appendix C) was performed to assess the clean-energy transitions of each of Ontario's connected neighbours, as well as their future ability to export clean energy. To guarantee the cleanliness of firm-imported electricity, firm imports were only permitted from Québec. Manitoba was not considered due to the distance to major Ontario load centres and insufficient transmission capability to enable imports.

Distributed Energy Resources (DERs)

DERs are distribution-connected facilities for local electricity generation, control and storage, and today represent at least 10,000 MW across the province. While the scenarios in this report did not distinguish between the province-wide transmission system and local distribution networks, DERs are included within the build-out of new resources.

DERs can help meet regional needs where there are existing constraints on supply, avoiding or deferring the need to build transmission infrastructure. Local electricity market pilots in York Region and Essex are exploring ways to coordinate local supply to meet local needs.

Recent research commissioned by the IESO shows that DERs have the potential to help meet Ontario's future electricity demand, and they are gaining momentum in Ontario. Infrastructure, capability and knowledge building across the province are creating a solid foundation for growth, and the IESO is working to integrate DERs into the electricity markets by 2026 to further support their expansion across the province.

Conservation and Demand Management and Mid-Term Review

The IESO's Mid-Term Review of the 2021-2024 CDM Framework includes findings and recommendations on how cost-effective CDM can best contribute to meeting evolving system and customer needs during the current framework and beyond. This includes analysis done earlier this year on how new and enhanced programs could be used to meet near-term capacity needs.

In response to these findings, the Minister issued a directive in October 2022 enhancing Ontario's CDM targets and budgets, optimizing the full potential of energy efficiency and bringing targets in line with the achievable potential estimates of the Mid-Term Review in the near-term. Current Save on Energy programs are on track to achieve all feasible energy-efficiency within the 2021-2024 framework.

Both the Mid-Term Review and this report highlight the potential for the IESO to expand the scope of its future CDM programs post-2024. They also highlight the importance of supporting efficient electrification to minimize the impacts of consumers switching from carbon-emitting fuels for space heating, transportation and other end uses. This will take focused effort, and the Mid-Term Review includes recommendations to move the sector in these directions.

Demand Forecasting

Demand forecasting is an attempt to predict future electricity demand so that the system can be effectively planned and managed, as electricity demand and supply need to be almost perfectly matched in real time. It aims to assess the causes of future changes in demand by looking at end uses and sector trends.

All sectors of the economy – residential, commercial, institutional, industrial, agricultural, transportation and others – contribute to province-wide energy demand, and the inherent uncertainty involved in predicting the future of all these elements makes forecasting demand challenging. It is clear, however, that as interest in decarbonization policies grow and economic activity increases, Ontario will see growth in electricity demand for the foreseeable future.

Capacity Expansion and Resource Adequacy Assessments

To build an adequate supply mix, the IESO undertakes a number of steps using tools, data and professional judgement. The starting point is a capacity expansion model (CapEx), which is used to assist in the design of an expanded resource mix. (More details can be found in Appendix B, section 1). This mix is run through a number of assessments to determine that it is capacity and energy adequate. At a high level, the approach is as follows:

1. Determine the least-cost supply mix based on the demand forecast, resource inputs and constraints using the CapEx tool.
2. Assess the supply mix to ensure that resource capacity adequacy is met. This determines if the least-cost supply mix satisfies Northeast Power Coordinating Council (NPCC) resource adequacy requirements.
3. Assess the supply mix in a production cost model to ensure that resource energy adequacy is met.
4. Conduct a screening of the supply mix for operability to understand the ability of the mix to manage a variety of conditions as they occur in real-time on durability, diversity and flexibility (further described below and in Appendix B, section 3).
5. Assess the supply mix to understand the ability of the system to maintain supply within established transmission planning standards (further described below and in Appendix B, section 2).
6. If the supply mix is deemed insufficient, restart the process at Step 1.
7. When a supply mix is deemed sufficient, it is then post-processed for reporting on metrics such as cost and emissions.

This approach to resource adequacy assessments is consistent with IESO system planning processes. (Further information can be found in the IESO's Annual Planning Outlook Resource Adequacy and Energy Assessment Methodology.) The resource adequacy assessment is an iterative process, along with the operability screening and transmission assessments, which are described in the next section.

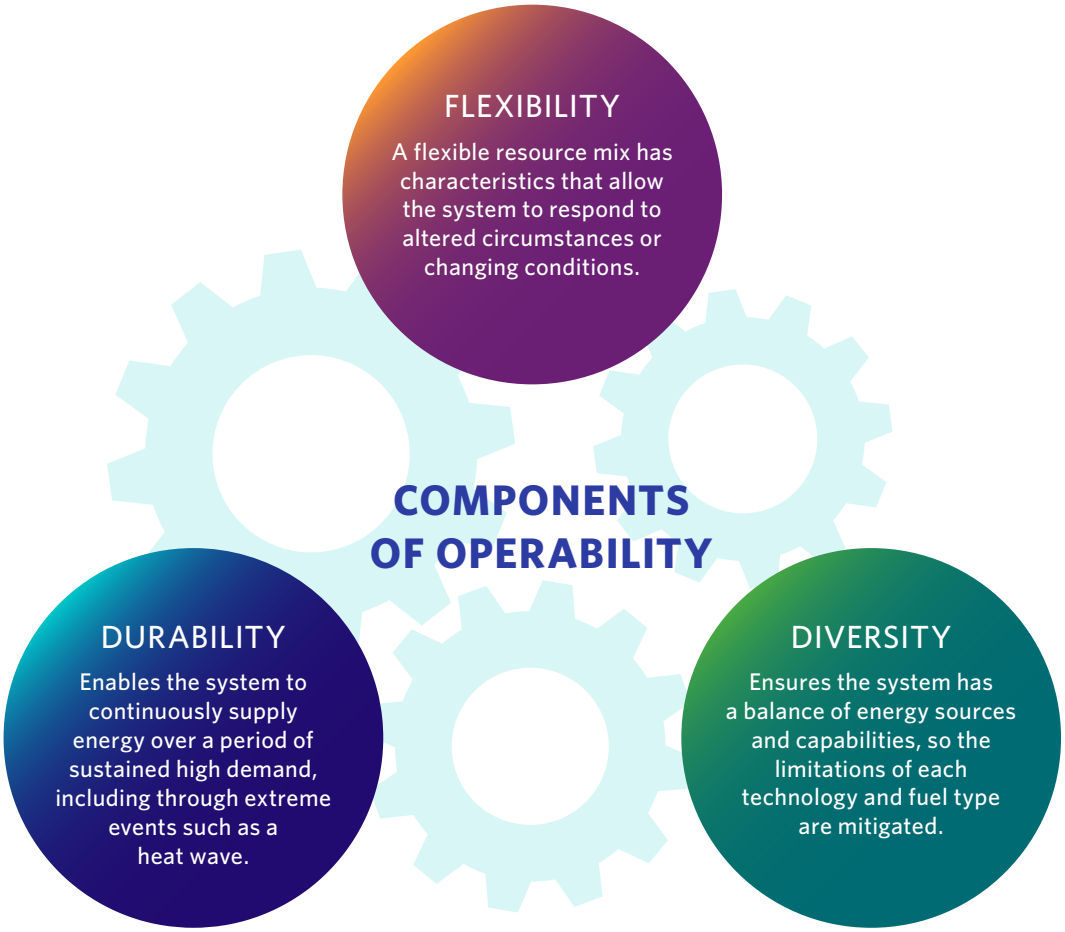
What is Capacity?

Capacity, or **installed capacity**, generally refers to the maximum output of a power station. Effective **capacity**, refers to the contribution a power station can reliably make to meet peak demand, taking into account factors such as fuel availability, ambient conditions and outages. For example, a station with an installed capacity of 150 MW could contribute only 30 per cent of that amount, and thus have an effective capacity of 45 MW.

Operability Screening

Operability refers to the ability to manage a variety of conditions on the power system as they occur in real time. It is achieved by having a resource mix that is flexible and diverse, with sufficient energy duration. By coupling resources with tools and software that improve manageability, the IESO can observe, monitor and direct the majority of resources across the system (see Figure 2).

Figure 2 | Components of Operability



For this report, the IESO conducted a limited operability screen on the resource mix for the Moratorium scenario, examining the durability, diversity and flexibility of the resource mix. For the modelled 2050 supply mix, the challenges identified in the Moratorium scenario are likely to grow, and with limited information on the operational behaviour of new technologies, the Pathways scenario could not undergo an operability screen.

The IESO plans to undertake further work in 2023 to understand the implications of increased penetration of variable resources on flexibility. A number of other future considerations were also identified that will require further study to assess the operability of the mixes. (Further information on future considerations can be found in Appendix B, section 3.)

Reliability Standards

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the effective and efficient reduction of risks to the reliability and security of the grid. NERC has begun to highlight the challenges of managing reliability with energy-constrained resources.

> Resource adequacy assessments have mostly focused on generation and transmission capacity available to serve peak demand. With the previous resource mix, real-time energy adequacy was assumed under that capacity umbrella and transmission was not highlighted as a requirement; however, recent extreme temperature events have shown energy adequacy to be a new dimension of risk given the changing resource mix and actual performance of the grid versus assumptions used in previous resource mix studies.
>
> **Energy Adequacy White Paper (nerc.com), December 2020**

New reliability standards are under development by NERC to address these challenges.

Transmission Analysis

The assessments in this report weighed existing and planned transmission capabilities against the two demand forecasts, evaluating the ability of the system to maintain supply within established planning standards and with the selected resource mixes. The assessments then looked at what system enhancements would likely be needed in the coming decades.

Although the capacity expansion model does not specify a location for any of the resources in the supply mixes, the options for siting certain generation types, such as pumped storage or SMRs, will be limited to a single or small number of areas. In addition, previous assessments of the feasibility of large installations of wind and solar provide guidance on the most likely locations for these types of facilities. These locational considerations informed the transmission analysis, helping to identify where new or upgraded transmission would be needed to enable the supply mix and ensure that demand can be supplied by the bulk transmission system.

If potential transmission solutions could not be implemented, (e.g., due to lead-time considerations), the assessment looked at opportunities to retain existing generation, as well as the potential to locate new supply that does not have limitations on potential siting in those areas of need.

Cost and Emissions Analysis

This report looks at costs from two perspectives: (1) cumulative capital investment in new infrastructure up to the applicable scenario study year and (2) annual system cost in the applicable scenario study year; with all costs in this report and the appendix in 2022 Canadian Dollars.

Under both scenarios, capital investment is represented as the overnight cost of "new steel in the ground" – i.e., there are no capital investments associated with resources such as demand response and conservation programs. "Overnight cost" is a common industry term, meaning the cost to build a project without consideration of financing, or the cost to complete a project if it were built "overnight".

An annual system cost includes the revenue requirements[4] for supply, transmission and distribution infrastructure; standby costs for demand response; conservation program costs; firm import agreement costs; and resource dispatch costs for a particular year.

In the Moratorium scenario, the focus is on the change in annual system costs in 2035 compared with a reference scenario with the same base supply mix, but instead of meeting reliability requirements with non-emitting resources, requirements in this reference scenario are met by extending all existing resources to the end of the study period, with incremental needs met by additional simple-cycle natural gas (a scenario approach similar to past APOs). With this comparison there is also a change in emissions and an implied cost of carbon can be calculated – i.e., the increase in annual system cost divided by the decrease in emissions.

In the Pathways scenario, the focus is on the total annual system cost in 2050, with the unit cost of demand – total annual system cost divided by total demand in the same year – calculated and compared with today's unit cost of demand. As there is no comparable emitting reference scenario for Pathways, an implied cost of carbon is not calculated.

Note that the final totals for both capital investment and annual system cost include a 25 per cent contingency. Adding a contingency is a consideration for unknown or unexpected factors, and is commonly used for a study of this nature. In addition to capturing general cost uncertainty, which varies by resource type and technology readiness, it is also meant to capture out-of-scope costs (e.g., the build-out of distribution infrastructure, which will be considerable under the Pathways scenario) and the potential for adherence to more stringent reliability criteria, requiring incremental resources.

Moratorium for the 2025-2027 Period

Addressing capacity needs arising in the 2025-2027 period, the Minister of Energy asked for an interim report, to be delivered in October 2022, that would inform immediate policy decisions for upcoming electricity sector procurements.

The IESO responded, in its Resource Eligibility Interim Report, and recommended that a diverse set of resources be included in these procurements. This included a significant investment in battery storage, balanced by natural gas capacity and other forms of non-emitting generation, to ensure reliability and affordability in the context of tight market conditions and supply chain disruptions.

The report concluded that a maximum target of 1,500 MW of new natural gas capacity will sufficiently complement other procurement streams, addressing short-term capacity needs and contributing to the province's longer-term energy transition.

[4] Revenue requirements can be contract costs or a cost of service. Both consider capital costs spread over the contract term or the life of the project, inclusive of financing, returns, taxes and accounting treatments, as well as annual fixed costs.

A Moratorium on New Gas Generation

To understand the feasibility of a moratorium on new natural gas generation, the IESO looked first at what resources would be needed to secure necessary supply for 2025-2027. The results are described in the Moratorium for the 2025-2027 Period section directly above.

It then examined the province's needs after 2027 and analyzed a scenario up to 2035 that addressed projected demand by adding only non-emitting resources to the current supply mix. The 2021 APO's planning and demand forecast was used as the basis for the scenario, as it was the most recent available data at the time the project began. As discussed below, adjustments were made to the forecast and supply mix to make the assessment more meaningful. In this scenario, the IESO only performed adequacy assessments for 2035, and therefore this report only shows capacity and energy results for that year.

Demand Forecast

The APO long-term demand forecast used in the Moratorium scenario covers the period from 2023-2042 (see Figures 3 and 4). It projects strong growth in the early to mid-2020s as a result of anticipated industrial mining projects, strong residential-sector growth and a robust commercial-sector recovery from the COVID-19 pandemic.

From the mid-2020s to the early 2030s, the forecast projects significant agricultural-sector growth and, in the early to late 2030s, expected increases in the number of electric vehicles in Ontario. (More information is available in the 2021 APO.)

Conservation and Demand Management

The APO demand forecast was updated to reflect the important role that managing demand should play in meeting future needs. Conservation, or energy efficiency, is a cost-effective non-emitting resource. Homeowners, businesses and communities can all play a larger role in saving energy and managing costs, and investments in energy-efficiency and demand management programs will be essential for maintaining reliability in the coming years.

As a result, an additional 2,200 MW[5] of demand reduction and 11.7 terawatt-hours (TWh) of energy savings, ramping up over the study time frame, was assumed along with existing efforts, together reaching a total of 3,100 MW of demand and 22 TWh of energy reduction by 2035. The amount is premised on best-in-class program delivery and incenting up to the full cost difference between baseline and efficient equipment, where it would be cost-effective from a system perspective. Successfully delivering the maximum potential savings would require increased, sustained investment in CDM programs, capability-building initiatives, and supporting marketing. It would also entail spending approximately $6.25 billion over the 2023-2035 period.

Figure 3 | Moratorium Scenario versus APO Peak Demand

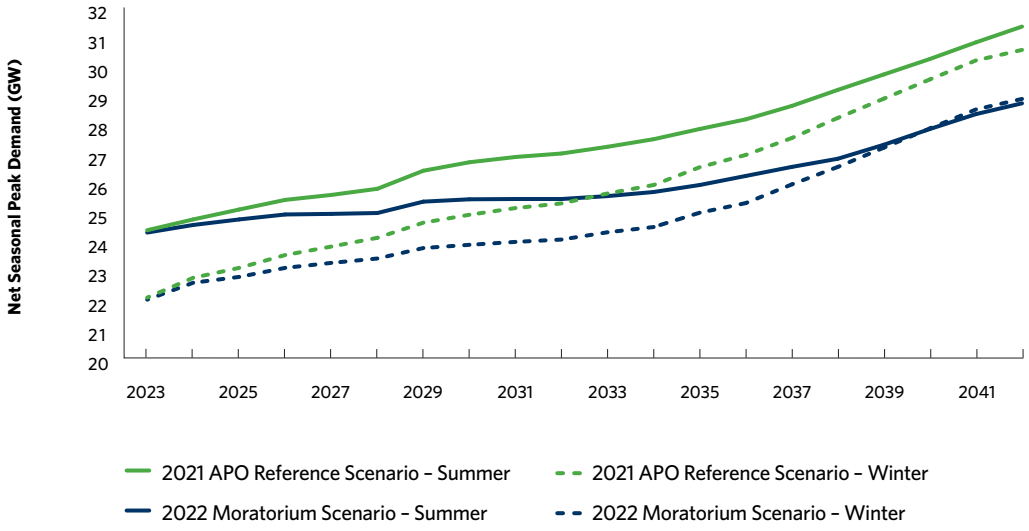
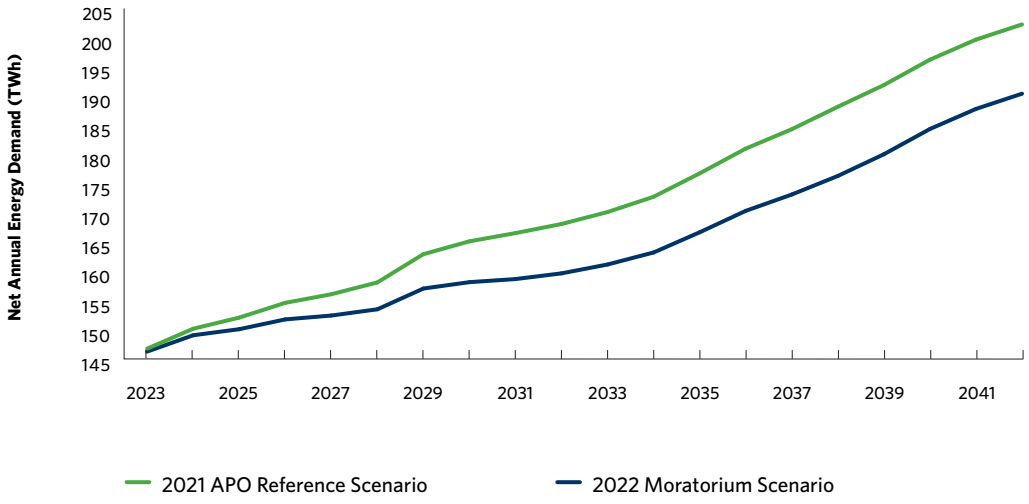


Figure 4 | Moratorium Scenario versus APO Annual Energy Demand



[5] As informed by the IESO and Ontario Energy Board's 2019 Electricity and Natural Gas Conservation and Demand Management Achievable Potential Study, Scenario B, maximum cost effective savings scenario. The IESO's Mid-Term Review undertook a 2022 refresh exercise of this study and confirmed the availability of significant cost-effective achievable CDM potential, with deeper savings over the longer term. Timing considerations did not allow for the 2022 refresh results to be incorporated in this report's modelling.

Resource Build-out

The next step in the process was to identify the base supply mix that would operate throughout the time frame of the study. The base supply mix identified in Figures 5 and 6 as "Today's Capacity Remaining in 2035" is made up of all facilities that exist in 2024 that are expected to still be in operation in 2035. It was assumed that this would include all existing non-emitting resources. Based on our assumptions, natural gas facilities began to retire over the study time frame, but were allowed to continue operating if they were needed for reliability purposes or if they were economically feasible to run. Natural gas is therefore reduced to about 8,000 MW in 2035 from the current fleet of about 10,000 MW. This reduction in gas was enabled by nuclear refurbishments, new SMRs, additional supply and significant conservation savings.

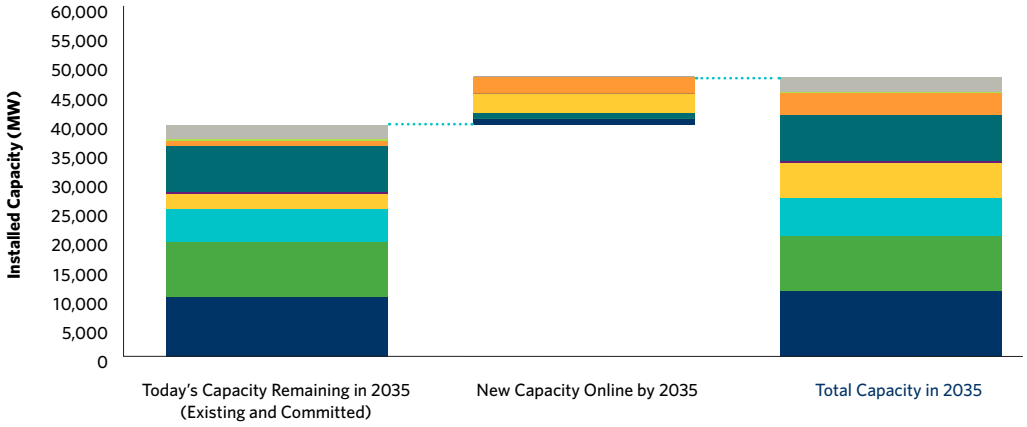
In addition, to ensure the exercise was as timely and relevant as possible, the actual or expected results from 2022 resource procurements and announced government policy were also added. These included:

- More than 700 MW of capacity from the IESO's first Medium-Term Request for Proposals, completed in June 2022;
- A 300 MW SMR, assumed to be in service in 2029; and
- 4,000 MW of supply (2,500 MW of battery storage and up to 1,500 MW of natural gas) from the Long-Term 1 procurements, assumed to be in service by 2027.

By 2035, the base supply mix had approximately 39,700 MW of installed capacity, including refurbished nuclear resources (see Figure 5, "Today's Capacity Remaining in 2035").

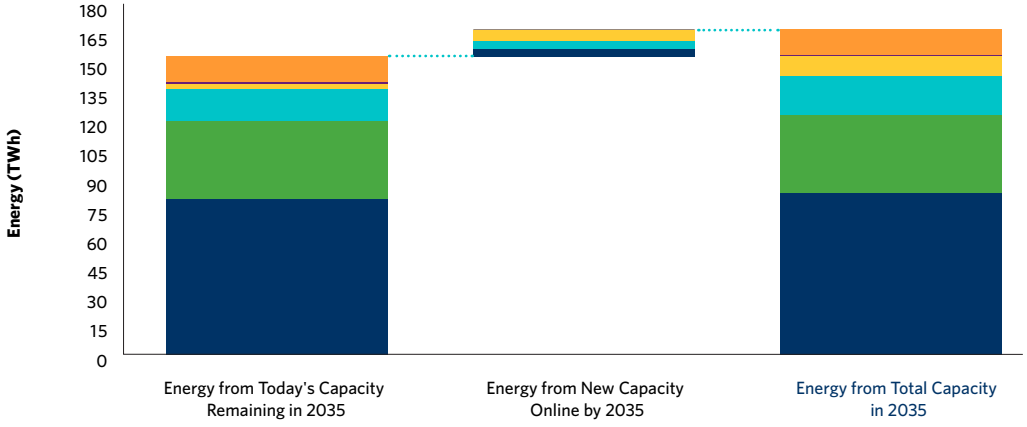
To meet projected demand in 2035, new supply was added throughout the study time frame according to need, cost, build time and other factors. Options available to "compete" included all developed non-emitting technologies except low-carbon fuels.

Figure 5 | Moratorium Scenario – Installed Capacity in 2035



	Today's Capacity Remaining in 2035 (Existing and Committed)	New Capacity Online by 2035	Total Capacity in 2035
Storage	2,507	0	2,507
Imports	331	0	331
Demand Response	808	2,885	3,693
Natural Gas	7,840	0	7,840
Bioenergy	415	0	415
Solar	2,668	3,400	6,068
Wind	5,533	900	6,433
Hydroelectric	9,348	0	9,348
Nuclear	10,248	1,000	11,248
Total MW	**39,697**	**8,185**	**47,882**

Figure 6 | Moratorium Scenario – Energy in 2035



	Energy from Today's Capacity Remaining in 2035	Energy from New Capacity Online by 2035	Energy from Total Capacity in 2035
Storage	0	0	0
Imports	0	0	0
Demand Response	0	0	0
Natural Gas	13	0	13
Bioenergy	1	0	1
Solar	3	6	10
Wind	16	4	20
Hydroelectric	40	0	40
Nuclear	80	3	83
Total TWh	**153**	**13**	**166**

By 2035, about 5,300 MW of new solar, wind and nuclear capacity has been added. In the capacity expansion tool, new solar was first added in 2029 and then consistently throughout the study period to support summer peak demand. Wind came online in 2030, and SMRs in 2031, to meet energy requirements. About 3,000 MW of demand response was also added to the fleet.

New large hydroelectric and nuclear facilities were not selected due to lead times that extended beyond the horizon of this scenario. As firm imports from Québec would require resource development in that province,[6] they proved to be costly and were also not selected. Finally, with 2,500 MW of battery energy-storage systems included in the base supply mix, the value of additional storage diminished, hindering its selection.

As shown in Figure 6, nuclear, hydroelectric and other renewables continue to provide baseload energy, while storage and demand response are used as peaking resources with minimal output. Of the 8,000 MW of natural gas remaining by 2035, about 5,000 MW was selected for energy adequacy. The 3,000 MW balance was determined to be needed for reliability services, including flexibility – i.e., the ability to provide energy quickly to respond to unexpected changes on the system – and emergency back-up. Energy produced from this amount is expected to be limited, along with its impact on emissions.

By 2035, total capacity reaches about 47,900 MW, compared with about 38,000 MW today. (For effective capacity data see Appendix A, Tab 10 and 11.)

This mix was assessed and found to be capacity and energy adequate.

[6] Hydro-Québec's recent strategic plan notes that "After several years of record energy sales across all our markets, tightened balances will prompt us to focus on maximizing the value derived from our clean energy." Québec's submission for NERC's Long-Term Reliability Assessment identifies the need to import/build more generation beginning in the late 2020s.

Transmission

Planning for a future that will require extensive amounts of new generation and the transmission to deliver it involves the careful consideration of many factors, including the cost and timing of development. For example, transmissions assessments indicated that in Toronto and York Region, existing gas will be needed in the Moratorium scenario because the new and/or expanded transmission infrastructure to replace it cannot be completed by 2035.

Overall, the new generation in the Moratorium scenario would require additional bulk transmission system infrastructure in the City of Toronto, York Region, east of the Greater Toronto Area, west of Barrie (Essa) and in both northwestern and northeastern Ontario. The IESO will ensure that future bulk and regional planning activities in these areas further assess the identified needs and reinforcement options and make recommendations for next steps, including development work. In particular, upcoming regional planning activities for both Toronto and York Region will need to examine options for the eventual replacement of the local reliability benefits provided by existing gas.

TABLE 3: TRANSMISSION FACILITIES NEEDED

Facility Needed	# of Facilities/Kms of Line	Location
New autotransformers	2	Essa, Toronto (Leaside)
New static volt-ampere reactive compensators	4-5	Northwest and Northeast
Refurbished 230 kV (kilovolt) lines	55 km	East (GTA East)
New 230 kV lines	5-20 km	Essa/Toronto (York Region)
New 500 kV lines	550 km	Northeast (Pinard to Hanmer)

This build-out is estimated to have a capital cost of up to $2.1 billion by 2035, over and above what is currently planned or underway. (Further details on the scope and drivers of each reinforcement are included in Appendix B, section 2.)

These findings relied on the implementation of existing transmission plans that are currently in various stages of development. This would allow the projected additional generation in the northeast and northwest to contribute to meeting provincial needs and to ensuring that sufficient supply is available in various areas across the province under the Moratorium scenario. Since these plans are already committed to meet existing needs, they form part of the 2021 APO base case.

Moratorium: Conclusion and Outcomes

The conclusion from this assessment is that a moratorium on the acquisition of new gas can be feasible after current resource procurements, but that it requires action: building on the CDM momentum; acquiring new, non-emitting resources to meet new demand and replace retiring resources; and developing the needed transmission. It also requires focused research and analysis to develop a mix of resources that can reliably replace the operability services provided by existing natural gas plants as they retire.

While Ontario's gas fleet will increase to meet mid-decade needs, the Moratorium identified the potential opportunity to reduce the overall amount of natural gas in the system from up to approximately 12,000 MW in 2027 to 8,000 MW in 2035. Of this amount, about 5,000 MW would be needed for capacity and energy, representing a 60 per cent reduction from 2027 levels. As noted above, the remaining 3,000 MW would be needed on standby for operability reasons, as the important characteristics of gas must remain available to Ontario's power system and no like-for-like replacement is yet available. Energy contributions from this amount, however, are expected to be marginal in this scenario.

In terms of emissions, the change in the resource mix and energy contributions results in an eight mega-tonne (Mt) per year decrease in forecasted CO_2e emissions in 2035, a nearly 60 per cent reduction from the APO 2021 forecasts.

The revenue requirement for this new infrastructure, combined with costs for incremental CDM programs[7] and changes to system operation, would result in a $1.9 billion net increase in annual total system costs by 2035, approximately an eight per cent increase over today's costs. This will undoubtedly lead to increased electricity costs for consumers. However, some studies[8] suggest that by 2050 these increases could be offset by savings from more efficient equipment like heat pumps and electric vehicles, as well as reductions in fossil fuel costs for transportation and heating.

With an eight Mt CO_2e decrease in emissions by 2035, the implied cost of carbon (the net increase in annual total system costs divided by emissions saved) would be $240/t$CO_2e$. (For further information on system costs, see Appendix A, Tab 8.)

[7] CDM is considered through decreased demand and associated program costs.

[8] See Electric Federalism: Policy for Aligning Canadian Electricity Systems with Net Zero, The Canadian Climate Institute, May 2022, p. 47, and "Electricity Affordability and Equity in Canada's Energy Transition, Dolter, Brett and Winter, Jennifer, the Canadian Climate Institute, August 2022.

Assessing a Pathway to a Decarbonized Future

The Pathways scenario looks at the time frame for decarbonizing Ontario's electricity system in the context of high electricity demand based on substantial electrification in other sectors.

Using the same supply base case as the Moratorium scenario, Pathways focused on 2050, assuming non-emitting resources would be available for 25 years for solar and 30 years for biomass and wind from their commissioning dates. Hydroelectric facilities were assumed to be available for the duration of the study time frame. In this scenario, up to the year 2035, gas plants were allowed to operate until they reached 25 years of age. After 2035, they were retired at the end of their contract, but kept available for reliability. This approach to the life of gas plants was informed by the draft framework for the Clean Electricity Regulation released in 2022.

Adequacy assessments were performed only for 2050, and as a result the scenario only shows capacity and energy results for that year. An operability screen was not performed, but further work will be undertaken.

Demand Forecast

The Pathways scenario, which looks out to 2050, assumes high levels of electrification in the economy. The scenario was created based on theoretical, aggressive, policy-driven electrification in three major sectors: transportation, building heat and industrial process. To develop this scenario, we did not undertake a cost-optimization exercise comparing different decarbonization options on the demand-side. The upcoming work performed by Ontario's Cost-Effective Energy Pathways Study, commissioned by the Ministry of Energy, will provide more insight on the possible evolution of demand in Ontario.

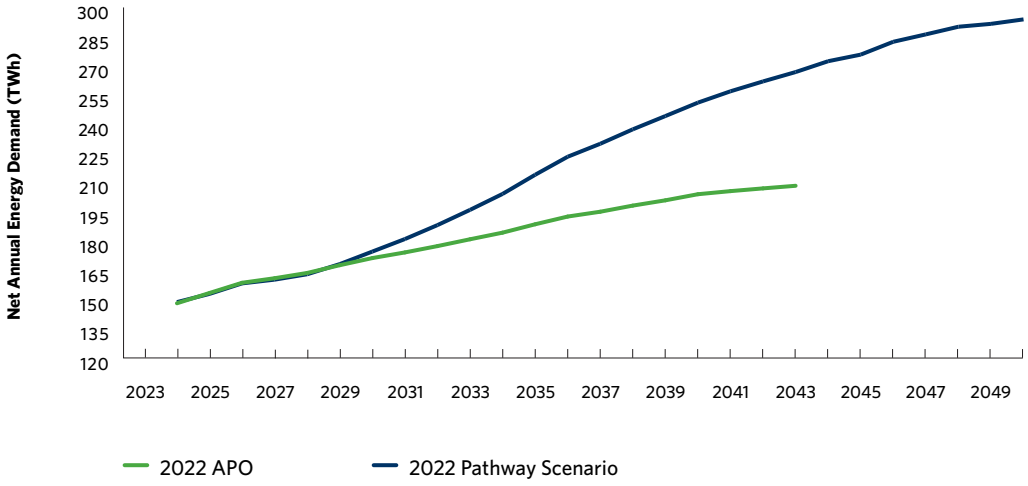
Major scenario assumptions include:

- **Buildings:** A nine-year transition from predominantly fossil-fuelled space and water heating to electric heat pumps, by 2030 for new residential and commercial buildings in Toronto, and by 2035 for the rest of the province. Technological improvement in cold-weather heat pump technology was assumed.
- **Transportation:** Electrification of passenger vehicles aligned with federal regulations; incremental electrification of medium and heavy-duty vehicles, including municipal transit buses, rail transit, and other mobility; and freight vehicles assumed to be fuel cell powered with hydrogen fuel.
- **Industry:** Broad substitution of natural gas fuel to electricity, roughly 20 per cent of current levels by 2050. If the low-carbon hydrogen is manufactured in Ontario, this new industry will represent a significant new load that is not currently included.
- **Conservation:** Assumes savings consistent with the maximum achievable potential from the 2019 IESO Conservation Achievable Potential study.

The demand scenario is based on an assumption of normal weather patterns and does not consider extreme weather events or the projected increase in overall temperature. These changes could have a significant impact on future demand, but are beyond the scope of this project.

As a result of the assumed electrification, the scenario has an average annual growth rate for 2023-2050 of 2.7 per cent for energy reaching an annual energy consumption of approximately 300 TWh by 2050, as shown in Figure 7.

Figure 7 | Energy Demand



Capacity increases by 1.5 per cent per year for summer (Figure 8) and 3.8 per cent for winter, resulting in a winter peak of approximately 60 GW by 2050 (Figure 9).

Figure 8 | Annual Summer Peak Demand

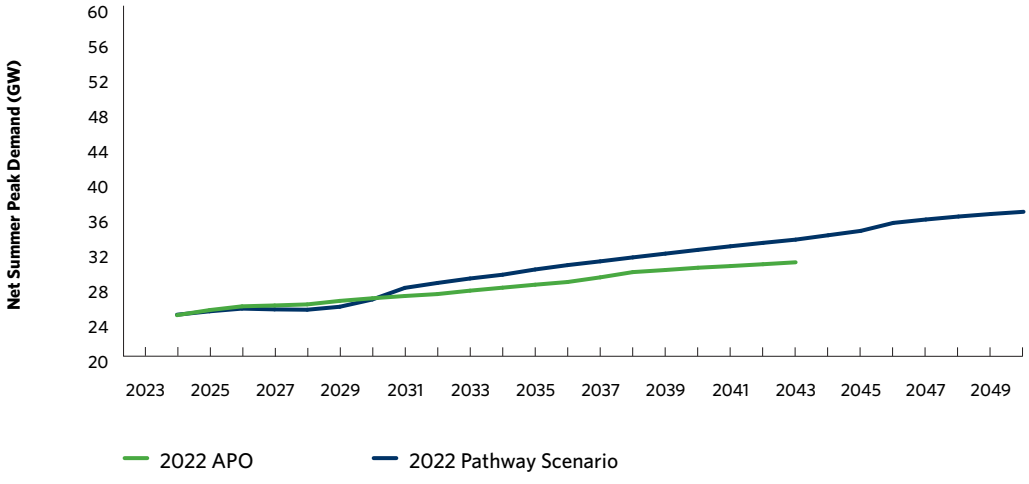
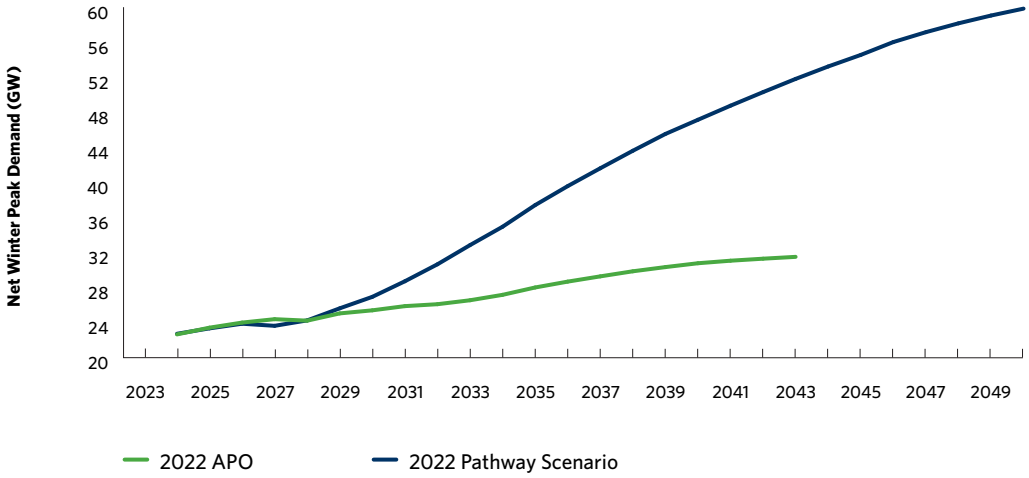


Figure 9 | Annual Winter Peak Demand



The system becomes winter peaking by 2030, largely as result of increased electrification of transportation – i.e., evening or overnight charging – and of heating requirements in buildings. This electrification also changes the shape of system demand during winter, resulting in spring and fall peaks that are higher than summer peaks.

The new profile has up to three ramps per day of 6,000-10,000 MW (see Figure 11), compared with ramps of 2,000-5,000 MW today, attributed to the forecasted new overnight coincident demand from the charging of electric vehicles after business hours and the adoption of electrically powered space heating in the winter season. Managing these ramping requirements would represent a significant operability challenge.

There would likely be an opportunity to manage winter demand through thermal storage and demand response, but there is still considerable uncertainty around the impact on daily demand of future heat pump and electric vehicle requirements. Summer demand profiles do not show significant changes (see Figure 10).

Figure 10 | Summer Daily Load Shape Hourly Profile

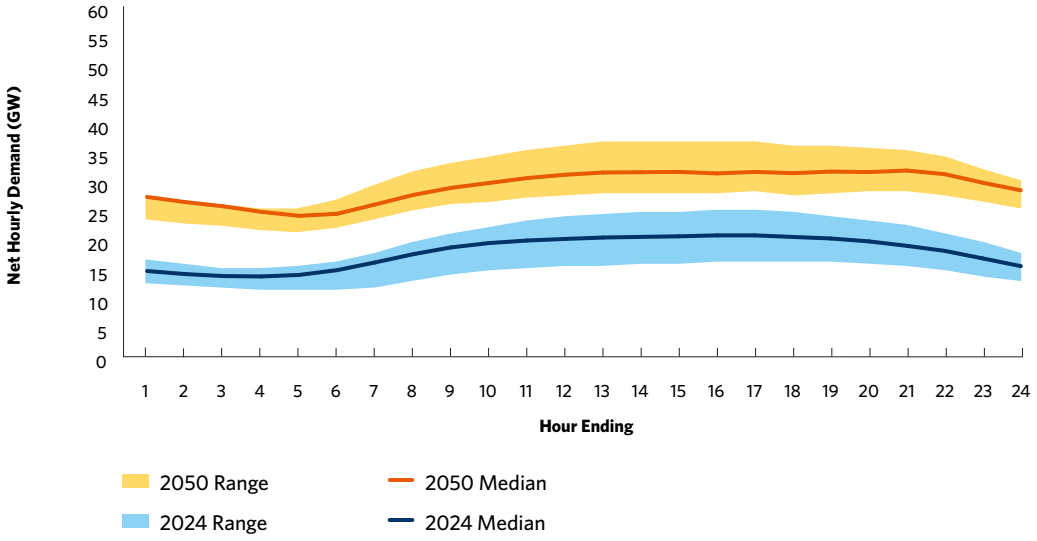
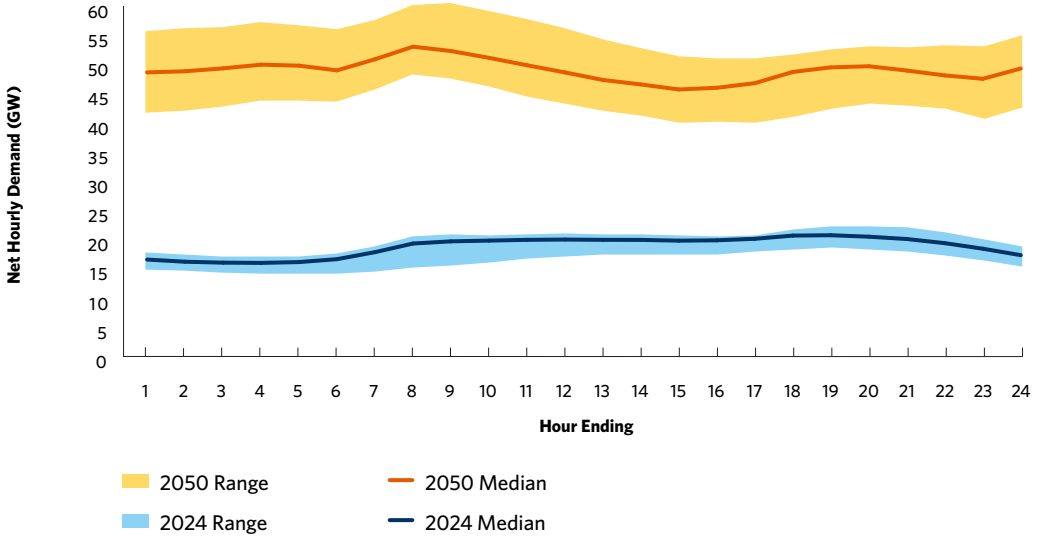


Figure 11 | Winter Daily Load Shape Hourly Profile



As with the Moratorium scenario, this forecast reflects a ramping up of CDM savings, reaching 4,650 MW of demand reduction in 2050[9] at a cost of $11.5 billion over the 2023-2050 period.

[9] These amounts are in line with the maximum potential scenario of the IESO's 2019 Conservation Achievable Potential Study.

Resource Build-out

By 2050, about 20,000 MW of today's supply is still in operation, made up primarily of large nuclear reactors and hydroelectric. Most existing renewable generation is assumed to have reached its end of life, while natural gas is phased out consistent with the zero-emissions goal.

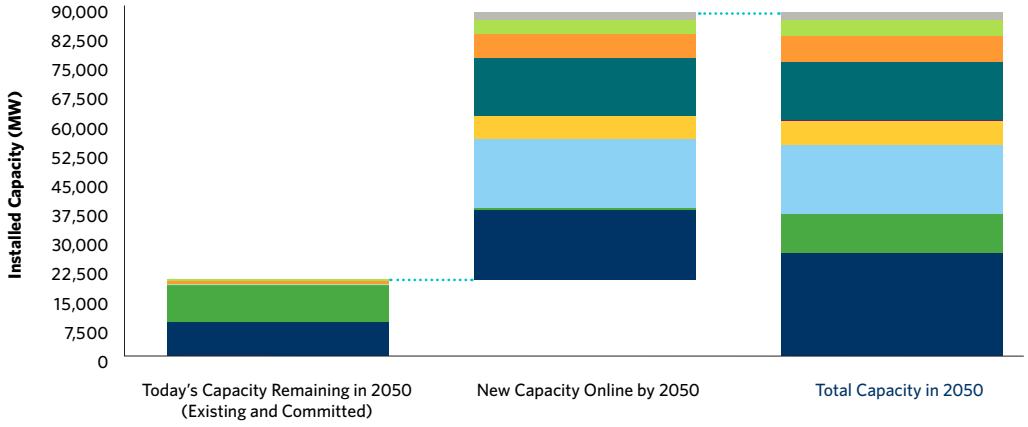
In order to reliably meet the new winter peak demand of 60,000 MW, an additional 69,000 MW of installed capacity is added, in addition to nearly 5,000 MW of CDM that is already included in the demand forecast (see Figure 12).

This scenario includes an additional 17,800 MW of nuclear supply. By 2050, as most of Ontario's existing wind facilities will have reached their end of life, this scenario also includes an additional 17,600 MW of wind and 650 MW of new hydroelectric.

Solar resources provide value during summer peaks in the early years of the scenario. As the system transitions from summer to winter peaks, the value of these resources diminishes and incremental capacity levels off at 6,000 MW in 2036. In addition, as under the Moratorium scenario, the existing 2,500 MW of batteries limited the value of further short-term storage through to 2035. An additional 2,000 MW of long-duration storage is added in the late 2030s to meet adequacy needs.

Assuming its availability in 2036, the analysis suggests that hydrogen becomes a cost-effective[10] resource for reducing peak demand.

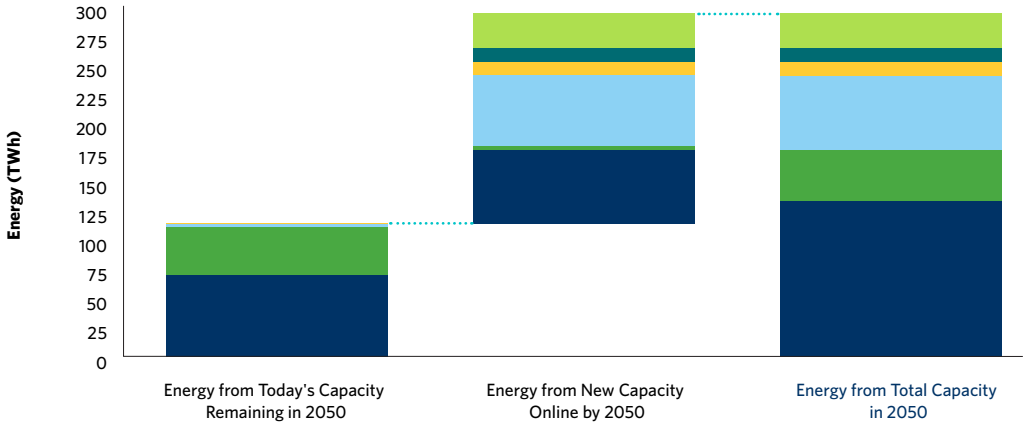
Figure 12 | Pathway Scenario – Installed Capacity in 2050



	Today's Capacity Remaining in 2050 (Existing and Committed)	New Capacity Online by 2050	Total Capacity in 2050
Storage	0	2,000	2,000
Imports	331	3,800	4,131
Demand Response	808	5,936	6,744
Hydrogen	0	15,000	15,000
Bioenergy	41	0	41
Solar	259	6,000	6,259
Wind	160	17,600	17,760
Hydroelectric	9,348	657	10,005
Nuclear	8,653	17,800	26,453
Total MW	**19,600**	**68,793**	**88,393**

[10] Although estimates are based on the most reliable information available at the time of writing, considerable uncertainty remains around cost assumptions for various fuels over the study time period.

Figure 13 | Pathway Scenario – Energy in 2050



	Energy from Today's Capacity Remaining in 2050	Energy from New Capacity Online by 2050	Energy from Total Capacity in 2050
Storage	0	0	0
Imports	0	30	30
Demand Response	0	0	0
Hydrogen	0	12	12
Bioenergy	0	0	0
Solar	1	11	12
Wind	2	62	63
Hydroelectric	41	3	44
Nuclear	70	63	133
Total TWh	**113**	**181**	**294**

Using Ontario's existing interties with Hydro-Québec, as well as incremental new infrastructure in both Ontario and Québec,[11] this scenario includes 4,000 MW of imports. Given Hydro-Québec's current winter capacity constraints, which are outlined above, we assumed that the firm imports would be from new hydroelectric and new wind facilities built in Québec.

By 2050, the total installed capacity reaches about 88,400 MW. In contrast, current installed capacity is about 40,000 MW.

This mix was found to be capacity and energy adequate.

Operability and the future electricity grid

As discussed throughout this report, ensuring reliability is of paramount importance. For a system to be reliable, it must have the flexibility to respond to sudden changes as well as extreme conditions. Future supply mixes will not have some of the traditional resources that currently provide these services, and ensuring reliability without them contains many unknowns. It will require detailed planning studies that incorporate novel approaches, tools and a thorough understanding of the location and technological features of individual resources as they are integrated into the electricity grid. As a result, the IESO has not performed an operability assessment on this scenario. The IESO will work with peers and industry experts over the coming years to address this challenge.

[11] Incremental new infrastructure would include a new intertie between the two provinces and additional reinforcements in Ontario to deliver the capacity to the load centre in the GTA. It would also include necessary reinforcements on the Québec side.

Transmission

The transmission requirements for the Pathways scenario are extensive. In order to achieve a starting point for a system that is capable of incorporating the resources identified and reliably supplying the forecast demand, a significant build-out of Ontario's existing 500 kV network would be required, focusing on paralleling the existing network where possible. Beyond reviewing the impact of different levels of reinforcement to the 500 kV network, the need for an additional 230 kV of bulk reinforcements was also identified to enable the supply mix. (Full details are available in Appendix B, section 2.)

Meeting Forecasted Demand

The challenge of connecting the forecasted demand can be illustrated by considering some high-level assumptions around how many new load supply stations (i.e., transformer stations supplying distribution customers) would be required throughout the province:

- Taking into account existing load supply stations, and assuming that a new station would supply approximately 250 MW of winter load, it would require anywhere from 150 to more than 280 new stations to meet forecasted demand, depending on whether if those stations are fully utilized.
- Costs range between $5 billion and $10 billion based on recent figures for a standard load supply station in a non-urban environment, assuming no work is required on the upstream transmission system and not accounting for downstream distribution costs.
- This would mean that between five and 10 new stations a year, on average, would be needed to meet forecast winter demand in 2050, with a yearly pace potentially outstripping the number of new stations that have been developed across the province in the last decade.

Overall, the cost of building out the bulk 500 kV and 230 kV system to meet the Pathways scenario is estimated to be between $20 billion and $50 billion. This estimate includes new 500 kV and 230 kV network lines and terminations, and new 500/230 kV and 230/115 kV auto-transformation. If 500 kV reinforcement through northwestern Ontario to Manitoba were also needed due to load growth or constraints on resource siting, this could result in an additional $7 billion to $16 billion in costs. The costs for 500 kV lines and terminations are directly informed by the 500 kV reinforcements modelled. The range of cost for 230 kV lines, terminations and for all auto-transformation was informed both by the reinforcements modelled and the unit costs per MW of load growth, assuming typical equipment capabilities.

Many of the needed investments will be challenging to implement given their location within major load centres and populations, which makes land more challenging to acquire, permitting more contested and construction more expensive if undergrounding is necessary. Aside from the bulk reinforcements needed to support growth in the load centres, the Pathways scenario also necessitates major investments in the local distribution system, including step down stations required between the transmission and distribution network, and distribution infrastructure for final connection to the customer. The cost and siting challenge for the required stations and distribution infrastructure will also be substantial.

Pathways: Conclusion and Outcomes

This scenario illustrates the magnitude of the effort required for Ontario to decarbonize its electricity system while responding to economic development and electrification. Focusing on 2050 to align with international targets, this study highlights the goals we are attempting to achieve. It demonstrates an immense build-out of the province's transmission, distribution systems and resources that could more than double Ontario's installed capacity, and that would need every known or potential resource available today. It also requires replacing the necessary services provided by gas, which no resource alone today can do.

We can garner many insights from this scenario, but it is also important to acknowledge its limits. This resource mix was assessed for energy and capacity adequacy in 2050; an operability assessment was not performed. In addition, we did not perform adequacy assessments for the years before 2050. Further planning work is necessary to understand how to manage the transition in a reliable way from now to 2050.

This scenario relies heavily on low-carbon fuels for intermediate, peaking and flexibility needs. Currently there is no like-for-like replacement for the operating characteristics of natural gas. Low-carbon fuels might be able to fill this gap and would be a valuable addition to the supply mix, but they do not yet exist at scale and there are many barriers to commercialization. (See Appendix A, Tab 9.) If low-carbon fuels do not materialize, replacing natural gas will be an even more complex task, requiring more research and analysis into understanding how generation, demand, transmission and storage can be combined to replace gas. It may be possible to overcome all of these barriers, but it will require concerted effort by government and innovators.

In terms of both transmission and supply, the Pathways scenario would need $375 billion to $425 billion in new infrastructure investment, and result in an annual total system cost of approximately $60 billion by 2050. Alternatively, annual system costs can be considered per unit of demand at $200 to $215/MWh, an increase of between 20 per cent and 30 per cent from current unit rates.

Regarding consumer bills, it is difficult to determine a potential rate impact given the changing nature of energy consumption. However, an increased reliance on electricity will significantly increase the volume of consumption on bills compared to today's patterns. (Further information on system costs is available in Appendix A, Tab 8.) However, as noted above, some studies suggest that actual impact on total energy costs could be modest due to offsets and increased efficiency.[12]

[12] Canadian Climate Institute op. cit., p. 26

Natural Gas as a Transitional Resource to Ensure Operability

Natural gas generation currently plays a vital role in supporting grid reliability: it can generally provide continuous energy throughout the year, under all weather conditions; it can be ramped up or down within minutes to follow sudden or unexpected changes in demand or in the availability of other generators; and it provides reliability services that help stabilize voltages and frequencies on the transmission grid.

These important characteristics must remain available to Ontario's power system, which means that natural gas facilities are needed past 2035, or until reliable replacements have been identified, put into service and demonstrated their capability.

Developing a strategy to replace natural gas facilities requires a number of thorough, detailed assessments. As learned during Ontario's coal phase-out initiative, shutting down large facilities while maintaining reliability can take many years to achieve. Some of the learnings from Ontario's previous experiences include the following:

- Replacement resources should be procured, built, commissioned and operated at a satisfactory level of performance prior to the shutdown of facilities. Careful scheduling and demonstration of operation are critically important to ensuring that reliability can be maintained during transition years.
- Replacement resources are unlikely to have the same attributes as natural gas facilities. Low-carbon fuels such as renewable natural gas, for example, may be suitable replacements, but significant work must be done to ensure that they have both the right technical characteristics and that they are market ready in sufficient quantities by 2035. In the end it may be necessary to procure additional resources to ensure that all reliability attributes are replaced.
- Shutting down larger facilities can impact the transmission system. Studies should be conducted as each facility shuts down to understand the broader effects on the transmission system and to develop adequate infrastructure to maintain the security of the grid.

Coordinating outages is critical during the years where new replacement facilities and supporting infrastructure are under construction and commissioning. A staged approach allows facilities to shut down while broader impacts to the grid are managed effectively.

Replacing these facilities will be complex and will require detailed assessments and studies that will be a priority for the IESO going forward. In addition, it may require the development of new reliability standards.

Implementation Dependencies and Risks

While the energy transition will bring growth opportunities, the results of both scenarios demonstrate the complexities of achieving it. The electricity system will be relied upon to do more than ever while learning how to build and manage resources at a scale never before attempted.

Today, there is considerable activity underway in planning for Ontario's future reliability. The IESO's current resource procurements, along with CDM program development and efforts to enable emerging non-emitting resources, are all moving the province steadily forward toward meeting its coming needs.

Bridging the work of today with the needs of a decarbonized world will be challenging and complex, but Ontario has the experience to build on.

- After becoming the first jurisdiction in North America to completely phase out coal-fired generation in 2014, our electrical grid is now more than 90 per cent emissions-free – one of the cleanest electricity systems on the continent. On average, the system accounts for just under three per cent of the province's emissions;
- We have a mature sector, with established, knowledgeable electricity market participants, an experienced system operator and a respected energy regulator;
- We are part of the largest, most reliable grid in the world, and adhere to the requirements of North American standards authorities (NERC/NPCC) to ensure the reliability and security of Ontario's system;
- We have extensive experience with demand-side management programs; and
- We have a skilled, well-trained workforce and well-developed infrastructure to attract economic development.

That said, there are many dependencies and risks involved in making the transition to a decarbonized electricity system; these were brought to the IESO's attention during the stakeholder and community engagement process that has informed this body of work. Some of the more significant dependencies and risks are outlined below.

Policy certainty is a must: Provincial and federal policy in Canada must set mandatory goals for GHG emissions reductions, which, in turn, govern the direction of industry, business and consumer behaviour. Policy certainty – both in the near and long term – is vital to enabling investment in infrastructure, CDM, next-generation technology and decarbonization. Uncertainty around the future cost of carbon and emissions targets contributes to a challenging environment for investors and others interested in contributing to meeting reliability needs. Stakeholders emphasized that policy certainty is a prerequisite for decarbonization at scale.

Governance and oversight need to evolve with the challenge: The pace of electrification will depend on millions of individual choices by households and businesses regarding transportation, heating and cooling solutions and appliances. Those choices will be influenced by factors such as the relative cost of various options, the presence of supporting infrastructure and even geopolitical developments. This makes electricity system planning and investment challenging and may require an evolution in how the sector is governed to ensure an orderly energy transition.

Public support for decision-making is vital: Public support will be necessary to enable the transition. A recent report, Net Zero: An International Review of Energy Delivery System Policy and Regulation for Canadian Energy Decision Makers, concludes that "Durable public support for energy system transformation will need to rest on open, inclusive, transparent policy, planning and approval processes, engaging communities and citizens from beginning to end" (p. 5). This will involve acknowledging the costs and risks of the transition, as well as addressing how we pay for it.

Managing costs is a precondition to success: Stakeholders and experts are concerned about the effect of this energy transition on affordability, including the impact on industrial competitiveness and of rising costs on people with low incomes. This is a significant issue and highlights the need to adopt a cost optimized pathway. Recent analysis published by the Canadian Climate Institute shows that if the pathway is cost optimized, while electricity rates would increase, overall energy costs would decline as equipment becomes more efficient and the share of spending on natural gas and gasoline decreases.[13]

A partnership role for Indigenous communities is a prerequisite: Simply consulting Indigenous communities on planned system developments has never been a sufficient approach to electricity system planning: these communities expect to be full partners in the transition to a decarbonized future. Indeed, Indigenous communities, governments and organizations across Canada have been actively developing renewable-energy and transmission projects over the past two decades. Today, First Nations, Métis and Inuit entities are partners in, or beneficiaries of, almost 20 per cent of Canada's electricity-generating infrastructure, most of which is producing renewable energy. These communities are also seeking efficiency improvements in their buildings and want to see job creation in their communities. The electricity sector has already created a solid foundation of engagement with many Indigenous communities and is well positioned to build on this base.

Permitting and approvals must be streamlined: In Canada, it can take many years to build new energy infrastructure; the IESO's experience is that it can take four to five years for new wind and solar generation, 10 years for transmission networks and even longer for large, capital-intensive infrastructure. Stakeholders, communities, experts and infrastructure developers have made it clear that processes need to be enhanced and streamlined if Canada wants to build energy infrastructure at the scale needed to reliably decarbonize. It is imperative for all levels of government to review their processes, including the Impact Assessment Act, the Environmental Assessment Act, and siting approval and permitting processes.

[13] Canadian Climate Institute op. cit., p. 26

Siting grid-scale energy infrastructure will require the support of communities: All new infrastructure has to be placed somewhere and taking community concerns, needs and plans into consideration is critical to the expansion of the system. An estimate of land use required for incremental resources in the Pathways study would be almost 14 times the size of Toronto (see Appendix B, section 6). Some municipal representatives want to participate in the energy transition, but have noted that it is critical that they have some control over the type of infrastructure that will be built in their community. Thus, an important part of the system's planning process is looking at siting from a local perspective, as well as helping communities understand the challenges and opportunities of siting new infrastructure. The IESO is already working with government to preserve transmission corridors to enable future growth.

The impacts of decarbonization on the distribution system need to be considered: Decarbonizing Ontario will necessitate a considerable increase in the demand for electricity, which, in turn, will have a significant impact on the distribution system, local distribution companies and on the cost to the government and citizens. Toronto Hydro, for example, recently estimated that it will cost the distributor $10 billion by 2050 to build a grid that's capable of supporting the city's net-zero strategy. Coordination between the bulk and distribution systems is needed to ensure that this transition is reliable and efficient, and to maximize the value of DERs.

Access to capital, resources and labour may be challenging: The path to decarbonization is not only being considered in Ontario; jurisdictions around the world are planning or actively working on decarbonizing their energy systems over the next 25 years. As a result, competition for scarce resources is already becoming an issue, while volatile geopolitical realities and the COVID-19 pandemic continue to weaken supply chains. Many stakeholders have told us that finding skilled labour, capital and sources of supply are serious challenges to achieving decarbonization goals, and one study (see Appendix B, section 6) estimates that the 14,000-strong labour force currently working on electricity infrastructure projects in Ontario could need to increase six-fold for decades. The electricity sector and governments need to work together to develop a strategy to collectively face these uncertainties and sourcing challenges.

Innovation is important, but uncertain: While many of the technologies needed to decarbonize are already known and commercialized, many others, including low-carbon fuels and SMRs, are still in development. It will be important for Ontario and Canada to continue to invest in these, and other, innovations. As the system planner, however, we must consider scenarios in which these technologies become available, as well as scenarios in which they do not.

Conclusion

This report is the IESO's response to the Minister of Energy's request to evaluate a moratorium on the procurement of new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system.

The Moratorium and Pathways scenarios are not integrated power system plans, but analyses that identify potential opportunities and challenges to consider as Ontario electricity demand and its resource mix evolves. As well, although this scenario analysis is just the beginning of a discussion about how to decarbonize our system while maintaining reliability and managing cost, it provides a solid understanding of the scale of the work and clearly demonstrates the need to collaborate to address risks and dependencies.

This study found that a moratorium on new natural gas is possible after the province's current round of electricity resource procurements is complete – as long as development begins now. Informed by robust planning, Ontario must begin to acquire new non-emitting resources to meet the province's growing needs and must invest in pre-development work to better manage future uncertainty.

In response to the Minister's second question, we were able to develop an energy-adequate, decarbonized supply mix for 2050. Within the Pathways scenario, Ontario's system became zero-carbon in 2045 when the last natural gas plant retired after 25 years of operation, but further assessment is needed to determine the feasibility of this target as well as a cost-effective way to get to 2050.

In addition, the Pathways scenario points to a step change in how we grow and manage our electricity system. In order to meet a projected 60,000 MW of customer demand, Ontario will need all of the resources available to it to simultaneously expand and decarbonize. While many options are already available and understood (wind, solar, hydroelectric and large nuclear), others options such as SMRs and low-carbon fuels will require support, and their availability is not guaranteed.

Another key area of uncertainty identified in the development of this report relates to the proposed federal CER. It will be important that these regulations are informed by system planners and operators. For example, our assessment of the Moratorium scenario has led us to conclude that we will require 8,000 MW of natural gas on the system in 2035, particularly in the GTA, to ensure reliability. We will continue to work with the federal government to share our insights and perspective.

In this report, we have identified decarbonized scenarios for Ontario. Scenarios, however, are not enough. If Ontario wishes to make decarbonization a reality, a number of risks and dependencies must be addressed, including policy certainty, governance framework and regulatory barriers, siting and permitting, Indigenous and municipal partnerships and the management of costs. More broadly, this report underscores the need to galvanize collaboration with a wide range of stakeholders and communities as we explore ways to develop non-emitting resources to meet Ontario's energy needs.

For its part, the IESO will incorporate the learnings from this report into our core work, more explicitly integrating the risks of climate change and the ongoing energy transition into our planning and procurements. This includes ensuring that regional planning processes for Toronto and York Region address the unique challenges for local reliability of phasing out natural gas. We will also study options to replace the operability services currently provided by natural gas, and will continue to use our procurement framework to re-acquire existing resources.

Recognizing that Ontario's demand is growing, that existing resources are retiring, and that government may direct system decarbonization, the IESO has identified "no regrets" actions that are necessary to ensure that the electricity sector is ready to manage future uncertainty and risk. These actions are intended to keep options open while maintaining the flexibility to take advantage of opportunities as they emerge.

1. Advance Acquisition of Non-Emitting Resources to Meet Load Growth

The IESO is forecasting increased supply needs out to the end of the decade, with the possibility that electrification and economic development outpace projections. Ontario should continue to move swiftly to acquire new non-emitting resources and incentivize energy efficiency to meet emerging needs. Using its competitive and technology-diverse approach to resource acquisition, the Minister is requested to advance the efforts by directing the IESO to:

- Acquire new non-emitting resources this decade through future procurements. This includes continuing to issue a regular schedule of procurements into the next decade to create investor certainty.
- While current Save on Energy programs are on track to achieve all feasible energy efficiency within the current framework, expanded targets post-2024 need to be established. Offerings should be expanded to include efficient electrification and move away from time-bound CDM Frameworks to an enduring model that adapt funding and targets to Ontario's achievable potential. Discussions regarding appropriate targets and models should begin now to better leverage CDM as a resource to respond to evolving system, market, and customer needs.

2. Invest in Future Infrastructure and Innovation

There is an urgent need to begin investing in early development work to ensure that the grid is ready to support transformation into the next decade. A relatively small investment today ensures that the projects and technologies can deploy more readily to meet decarbonization targets. Recommendations to prepare for future infrastructure and innovation include the following:

- Sector partners should begin planning and siting work to identify potential new projects, including hydroelectric and nuclear. To enable this work, the Ministry should work with the Ontario Energy Board (OEB) and the IESO to develop a process to recover pre-development costs for OEB-regulated and IESO-contracted projects respectively, as applicable.
- The IESO should work with government and system transmitters to identify new, and protect existing, corridors of land as well as rights of way that will likely be needed for future transmission lines. The IESO should also leverage existing planning processes to identify and recommend development work for priority transmission investments to support decarbonization.
- There should be an increased focus on the work identified in Ontario's Low-Carbon Hydrogen Strategy, including recognizing if and how low-carbon fuels can contribute to the decarbonization of the electricity grid. Other investments in innovation and new technologies to meet future needs will also be critical. This includes continuing to expand efforts associated with the IESO's Innovation Framework as well as the Grid Innovation Fund.
- The IESO should pursue a deeper understanding of the role of long-duration storage such as pumped water and compressed air storage, contributing to reliability needs in the 2030s. This work could lead to procurements for long-duration storage that would allow the province to reduce its reliance on natural gas earlier.

3. Galvanize Collaboration

As there is no one solution to addressing the challenges and opportunities ahead, it is important to engage, understand and build support for a collective approach to how Ontario moves its electricity system toward decarbonization. This will require both sector stakeholders and communities to take an active role in implementing solutions. To achieve this, the IESO recommends that the Minister:

- Consult on the findings of the Pathways to Decarbonization report to ensure there is a broad understanding of the report's conclusions and to build acceptance for Ontario's energy policy moving forward;
- Continue to build partnerships with the federal and municipal governments to ensure a shared alignment of energy policy and approaches to managing the cost of Ontario's energy transition; and
- Continue to build partnerships with neighbouring jurisdictions, both in Canada and in the United States, that are undergoing similar energy transitions to share learnings and collaborate on potential solutions.

4. Break Down Regulatory Barriers

The scale of the energy transition is far reaching and will require new regulatory approaches to govern how Ontario makes decisions and develops and pays for its energy infrastructure. The IESO recommends that the Minister:

- Continue the work of the Electrification and Energy Transition Panel and establish a new long term energy planning process that is designed to address the energy transition; and
- Work with all levels of government and with regulators to ensure that approaches to regulating the development of new large infrastructure projects and expanding the use of CDM, DERs, and other innovative technologies are appropriate given the scale and pace of the challenge ahead.

5. Track Progress and Update Plans in an Open and Transparent Process

This study is a single scenario based on the information available to the IESO today. It is imperative that Ontario continue to update, track progress, and refine its planning in support of the energy transition. To do this, the IESO recommends that the Minister:

- Direct the IESO to establish a new and enduring process to track progress and plan for Ontario's energy transition. The planning should be incorporated into regular planning products such as the IESO's APO. The first iteration should account for the results of the actions identified above.

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https://denvergazette.com/news/business/heat-pumps-perform-below-par-at-high-altitude-cold-weather-xcel-nrel-research/article_776f0ddc-2740-11ee-88d9-2f1035a177e5.html

Heat pump performs below par at high altitude, in really cold weather, Xcel, NREL study shows

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Jul 24, 2023

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FILE PHOTO
COURTESY OF XCEL ENERGY

Jeff Lyng, area vice president for energy and sustainability policy at Xcel Energy, sat down with The Denver Gazette for a discussion about novel new research on the performance of air-source heat pumps in Colorado's climate.

The unique research, in partnership with the National Renewable Energy Laboratory (NREL), aims to determine the viability of heat pumps for space heating and their potential for reducing greenhouse gas emissions. The study found that air-source heat pumps perform up to 10% less efficiently at higher altitudes and cannot heat effectively at temperatures below 40 degrees.

Denver Gazette: When did this research begin?

Jeff Lyng: We started working with NREL in the fall of 2021 and put in place a project in which we really committed to evaluating heat pump technology at the thermal test facility in Golden, Colorado.

We're finding that electrification of heating holds great promise and we're very much in support of the state's beneficial electrification goals. We've also learned as part of this research (about) some of the limitations that heat pumps have. And so, we're bringing that learning and it informs the design of the Clean Heat Plan strategy that (Xcel) will file with the commission on Aug. 1.

DG: Do you think that the heat pump idea is viable in Colorado? I read through the report, and it indicates that there's some serious issues with heating in the winter. I noted that it said that people at high altitudes and in cold areas may need electric or gas supplemental heat in the winter. Doesn't that kind of defeat the purpose of having a heat pump?

Lyng: Well, you're zeroing right in on the important results of the study. I would say this. We do think heat pumps can deliver a significant amount of heating and emissions reduction in a reliable and affordable way when it's relatively mild outside – the spring and the fall. We have to think about the most extreme conditions, right, though when it's coldest out in the wintertime, and given where the technology is today, we do think customers are going to need some form of backup. They'll need to keep or maintain their existing gas furnace or boiler for those really, really cold temperatures.

And I think the NREL results, as you point out, highlight a few things. First, they demonstrate that much of this technology is tested at sea level. Of course, we're not at sea level in Colorado and in Golden – they see a degradation in performance due to less dense air, about a 10% decline in capacity and efficiency.

We have not yet looked at data of how the units perform in the field, and that's our next step. So, we've got about a dozen customers who have partnered with us and contractors who have partnered with us in the Front Range who have agreed to share their performance data for their heat pump, as well as their own personal experience, their customer experience, having that technology in their home.

What we're also going to do is install heat pumps at a test facility, a trailer in Leadville, Colorado, which is quite a bit higher in elevation yet still to see, again, how do they perform in real world applications.

But based on what we know right now and where the technology is today, which we have to be really clear-eyed about and realistic about, heat pumps do suffer a degradation performance at colder temperatures and that temperatures below zero, even cold climate heat pump technology ceases to operate as a heat pump and really operates more as an electric resistance technology, which, to us as grid planners, we need to think about. And what does that do to increase the electric demand in the wintertime from our electric system, the generation, the transmission, the distribution associated with that? … We think especially for existing homes, the best approach is probably a heat pump, plus the existing gas system for really, really cold temperatures.

DG: Do you have any quantification of how much (benefit), by way of carbon output, that this kind of combined system with natural gas, the supplemental heating and heat pump might produce?

Lyng: We'll get to an 80% or 85% emissions reduction by 2030, but we're not at zero yet. So, some of these emissions shift into the electric side of the business, as well. We do think it leads to lower emissions, but we've got to do the balance, if you will, of the remaining gas and the emissions associated with the electric system. … But as we've talked about, it's got its limits and that's where we think we need other things like clean fuels, hydrogen, renewable natural gas, as well as a lot more natural gas energy efficiency.

DG: Is there any quantification of the costs of installing these air source heat pumps?

Lyng: I think a typical average cost that we're seeing is about $20,000. And now it's going to vary. The mini-split systems – the systems that are more designed for a single room or a single zone are a little bit less expensive – but you might need more than one of them to heat an entire home. Centrally-ducted systems are a little bit more expensive, but of course they're designed to heat an entire home.

We've been offering incentives now for a few years, a $2,000 rebate. We have a proposal in front of the Public Utilities Commission to increase that to $2,200. There are a few other incentives that are about to be available, and it's kind of a once-in-a-generation moment in terms of the federal investment through the Inflation Reduction Act, which will have additional incentives made available through the Colorado Energy Office. … On top of that, there also is a federal tax credit, so we think we can take a significant bite out of the cost, but there's no question as you point out, this is a significant household investment to electrify heating.

DG: It kind of sounds like pushing a boulder uphill to convince people to spend what, $15,000 to $20,000 to install a heat pump when they already have a gas furnace.

Lyng: You raise, I think, a really valid point that, if customers that have existing gas systems that are operating (and) haven't reached their remaining usable life, it's quite a lot to expect that they would take out an existing system that's working and electrify it. And that's why we think a better approach for scale is when a customer is replacing their air conditioning, rather than put in a new air conditioner with higher efficiency, that's a great opportunity to install a heat pump or to consider doing it.

DG: Would the heat pumps work in tandem with a gas heating system in extreme cold weather?

Lyng: I would say it's a continuum at relatively mild temperatures, say above 40 degrees Fahrenheit. A heat pump might typically be able to supply all of the space heating needs. At lower than that, you're going to see more dual-system operation, where the heat pump is running, or the gas furnace or boiler also kicks on. So, you're running two heating systems at very, very cold temperatures.

DG: What specific heat pump are you using for this testing?

Lyng: We tested two. They're both by the same manufacturer – Bosch. We tested a mini-split system as I described, which has more of a wall diffuser. It's more for single zone. And we tested a centrally-ducted system. There are a number of other manufacturers, including Mitsubishi and others, that we'll get data from. But in the lab, we tested with Bosch.

DG: Do you do plan to verify these results by testing other manufacturers units?

Lyng: Yes, in the field, we're absolutely going to do that.

DG: And how long do you think it'll be before you get these results back in, or are you hanging it on Bosch right now?

Lyng: We have statutory deadlines that we have to achieve in order to be compliant with the clean heat standard. So, we move forward, nonetheless. We'll file a plan Aug. 1, and then as I mentioned, we have statutory targets to begin to hit in 2025, in 2030 … We will have results next spring of the mountain systems in Leadville, and we'll have results sooner than that from the front range systems.

DG: Is this a unique research that Xcel is doing, and has this been done before?

Lyng: It's very unique. What we're trying to do here is lead in evaluating how technology works in our climate. One thing to look at is how a piece of equipment performs in test conditions at sea level, but we're not at sea level. We're in Colorado … And so it's brand-new research that we've done working with NREL … The lab itself had to be reconfigured to be able to simulate Colorado's temperatures to even allow us to test this.

DG: And is Bosch involved in this to the point where they're looking at using these results to try to re-engineer their devices to work better in cold temperatures and high altitudes?

Lyng: Bosch is directly involved in this research, and the manufacturers are all trying to improve their performance. I think what will be interesting to see is how much innovation happens to serve high mountain climates and how much the market actually develops here.

Editor's note: This story has been edited for brevity and clarity.

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Performance Assessment of High Efficiency Variable Speed Air-Source Heat Pump in Cold Climate Applications

Gregory Shoukas, Eric Bonnema, Gokulram Paranjothi, Ramin Faramarzi, and Lauren Klun

Produced under direction of ComEd by the National Renewable Energy Laboratory (NREL) under Technical Services Agreement TSA-19-01159

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List of Acronyms

AHRI	Air-Conditioning, Heating, and Refrigeration Institute
AHU	air-handler unit
ANSI	American National Standards Institute
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers
ASME	American Society of Mechanical Engineers
BTU	British Thermal Unit
ComEd	Commonwealth Edison Company
COP	coefficient of performance
db	dry-bulb
dp	dew-point
DOE	U.S. Department of Energy
DX	direct expansion
EER	energy efficiency ratio
HSPF	heating seasonal performance factor
HVAC	heating, ventilating, and air conditioning
NREL	National Renewable Energy Laboratory
OAT	outdoor air (dry-bulb) temperature
OU	outdoor unit
RA	return airstream
RPM	revolutions per minute
RSM	response surface methodology
SEER	seasonal energy efficiency ratio
SHR	sensible heat ratio
TC	thermocouple
TMY	typical meteorological year
TTF	Thermal Test Facility
wb	wet-bulb

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Executive Summary

This project was part of an effort by ComEd's emerging technology program to evaluate the energy saving potential of new energy efficiency technologies. The focus of this technology assessment was to determine energy and peak demand savings potentials of a high-efficiency variable-speed, air-source, split system heat pump designed for cold climate applications. The results of this technology assessment will be used by ComEd and CLEAResult to determine considerations for future offerings in ComEd's Energy Efficiency Program.

The project utilized the National Renewable Energy Laboratory's (NREL) Thermal Test Facility to experimentally characterize cooling and heating performance of a high-efficiency heat pump split system under varying indoor and outdoor climate conditions. The selected climate conditions represented summer and low-temperature winter conditions in ComEd's service territory. The laboratory experimentation results were used to develop equipment performance curves required by the EnergyPlus® hourly simulation engine. Using typical meteorological year 3 weather data for the Chicago O'Hare airport, hourly building simulations (using the EnergyPlus engine) was utilized to estimate the annual energy savings of the high-efficiency heat pump in comparison to a standard efficiency heat pump unit in the following U.S. Department of Energy's (DOE) building codes program energy prototypes:

1. Single-family home
2. Strip mall
3. Low-rise office.

Figure ES-1 depicts the annual whole-building cooling and heating energy savings per square foot of conditioned floor area:

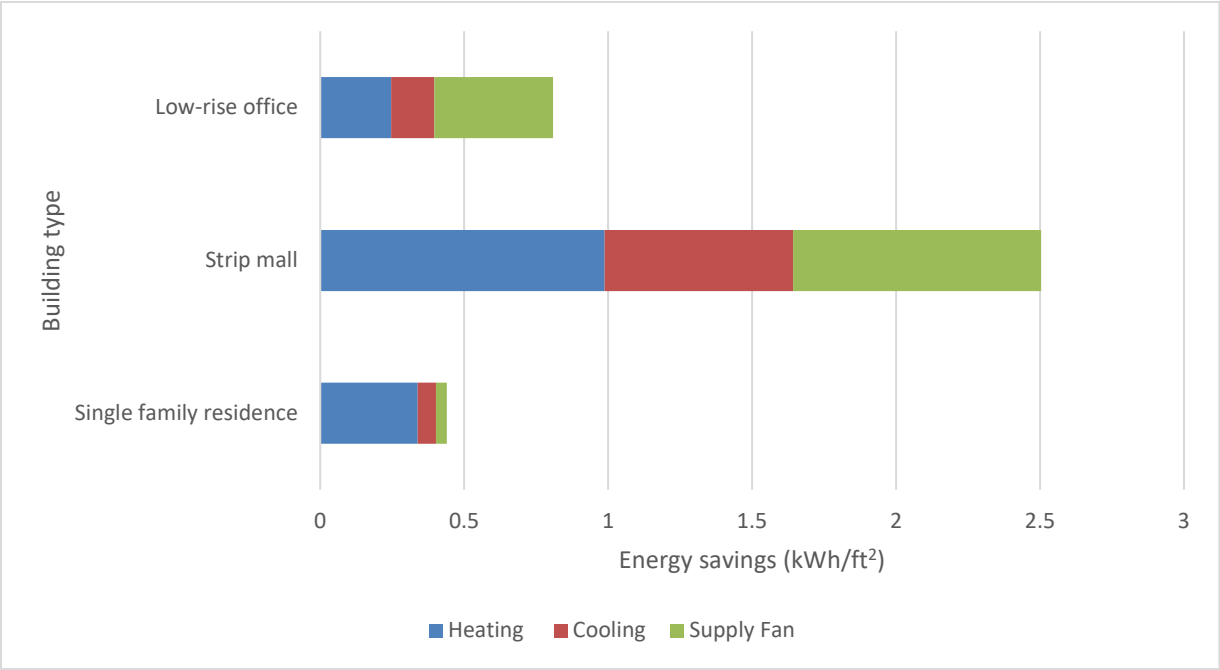

Figure ES-1. Energy savings per floor area for each building type and end use

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1 Introduction

This project was part of an effort by ComEd's emerging technology program to evaluate the energy saving potential of new energy efficiency technologies. The focus of this technology assessment was to determine energy and peak demand savings potentials of a high-efficiency variable-speed, air-source, split system heat pump designed for cold climate applications. The results of this technology assessment will be used by ComEd and CLEAResult to determine considerations for future offerings in ComEd's Energy Efficiency Program.

Recent advances in heat pump systems employ variable-speed compressor technology and electronically commutated fan motors. Compared to single-speed heat pumps, variable-speed systems can maintain higher heating and cooling efficiencies over a wider range of outdoor temperatures. For any given heat pump speed, the thermal capacity inherently decreases with falling outdoor temperatures. Variable-speed heat pumps can ramp up the compressor to increase the thermal output and compensate for the reduced capacity at lower outdoor temperatures. These advances are commercially available in a few configurations such as minisplit, multisplit, and ducted split systems. These system configurations are predominately used in residential applications.

This project utilized the HVAC Laboratory located at the National Renewable Energy Laboratory's (NREL) Thermal Test Facility (TTF) to experimentally characterize cooling and heating performance of a high-efficiency split system heat pump under varying outdoor climate conditions. The selected climate conditions represented summer and low-temperature winter conditions in ComEd's service territory. The laboratory experimentation results were used to develop equipment performance tables that could be used by the EnergyPlus® building simulation engine. Using typical meteorological year 3 (TMY3) weather data for the Chicago O'Hare airport, hourly building simulations (using the EnergyPlus engine) was utilized to estimate the annual energy savings of the high-efficiency heat pump in comparison to a standard efficiency unit in the following U.S. Department of Energy's (DOE) building codes program energy prototypes:

1. Single-family home
2. Strip mall
3. Low-rise office.

This document reports on the approach and results of the laboratory experimentation work and the building simulations associated with a high-efficiency, variable-speed heat pump designed for operation in cold climates. The document is organized as follows:

- Section 1 summarizes the technology description and project goals
- Section 2 details the experimental configuration and laboratory setup
- Section 3 documents the testing approach for performance mapping the equipment
- Section 4 discusses the EnergyPlus modeling approach
- Section 5 summarizes the annual energy savings results.

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1.1 Technology Description

The test unit used for this study was a five-ton Carrier® Infinity® Series heat pump with Greenspeed® (variable speed) intelligence. Table 1 summarizes the specifications of this unit.

Table 1. Table of Manufacturer's Performance Specifications

Carrier Infinity Series with Greenspeed Intelligence

Outdoor Unit (25VNA0060A) / Air-Handler Unit (FE4ANB006) / Thermostat (SYSTXCCITC01-B)

	Cooling	Heating
Rated Capacity [1,2] [BTU/h]	56,000	55,500
SEER [1] [-]	18.0	-
EER [1] [-]	12.7	-
Compressor Speed [RPM]	1,800–4,250	1,800–7,000
Outdoor Unit Fan Speed [RPM]	500–900	500–900
Indoor Unit Fan Speed [RPM]	1,185–1,885	750–1,750
Expansion Device	Thermal expansion valve	Electronic expansion valve
HSPF [2] [-]	-	12.0
COP [2] [-] @ 47ºF	-	3.86
COP [3] [-] @ 17ºF	-	2.22

[1] Cooling standard: 80ºF (27ºC) db 67ºF (19ºC) wb indoor entering air temperature and 95ºF (35ºC) db air entering outdoor unit.
[2] High heating standard: 70ºF (21ºC) db indoor entering air temperature and 47ºF (8ºC) db 43°F (6ºC) wb air entering outdoor unit.
[3] Low heating standard: 70ºF (21ºC) db indoor entering air temperature and 17ºF (-8ºC) db 15°F (-9ºC) wb air entering outdoor unit.

The Carrier heat pump's steady-state heating and cooling performance was evaluated over a wide range of outdoor conditions and typical indoor conditions. The thermal capacity and coefficient of performance (COP), a unitless measure of heating or cooling capacity over total power input, was assessed over the range of conditions discussed in Section 3.

In addition, two modes of equipment operation were characterized: comfort and efficiency mode. Comfort mode operates the equipment to provide better dehumidification during cooling and higher supply air temperatures during heating. Efficiency mode operates the equipment to provide the best energy efficiency while satisfying the thermostat temperature setpoint.

NREL designed an experimentation plan such that the unit operates under its embedded control algorithms to ensure a realistic assessment of the operation, performance, and energy consumption while varying environmental conditions. This operating approach is the most representative of the equipment's actual operation in a building and differs from the rating methodology outlined in the AHRI 210/240 (AHRI 2023) standard. This standard requires performance evaluation of the heat pump under limited test conditions while overriding the embedded controls via a third mode of operation called technician checkout mode.

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1.2 Project Goals

The goal of this project is to estimate the energy and demand savings of the high-efficiency heat pump in selected building types under typical Chicago-area weather. Steady-state heating and cooling performance data from laboratory experimentations were used to develop equipment performance tables. Performance tables were then integrated to the EnergyPlus (DOE 2021) simulation platform for modeling the energy performance of the high-efficiency heat pump in the following building types using typical Chicago-area weather data:

1. Single-family home
2. Strip mall
3. Low-rise office.

2 Experimental Configuration

The TTF is a 100% outdoor air psychrometric laboratory that delivers conditioned air to a test article. Through a custom, computer-based measurement and data acquisition system, the lab controls and maintains precise air temperature, humidity, pressures, and flow rates to precise setpoints. Four laboratory air streams in total are used to control and measure the psychrometric conditions at the inlet and outlet of the indoor and outdoor unit. Accurate, real-time measurements are recorded to determine the heat and mass transfer performance of HVAC equipment. Figure 1 highlights TTF's layout of the four inlet and exhaust airstreams used to test HVAC systems up to 10 tons in capacity.

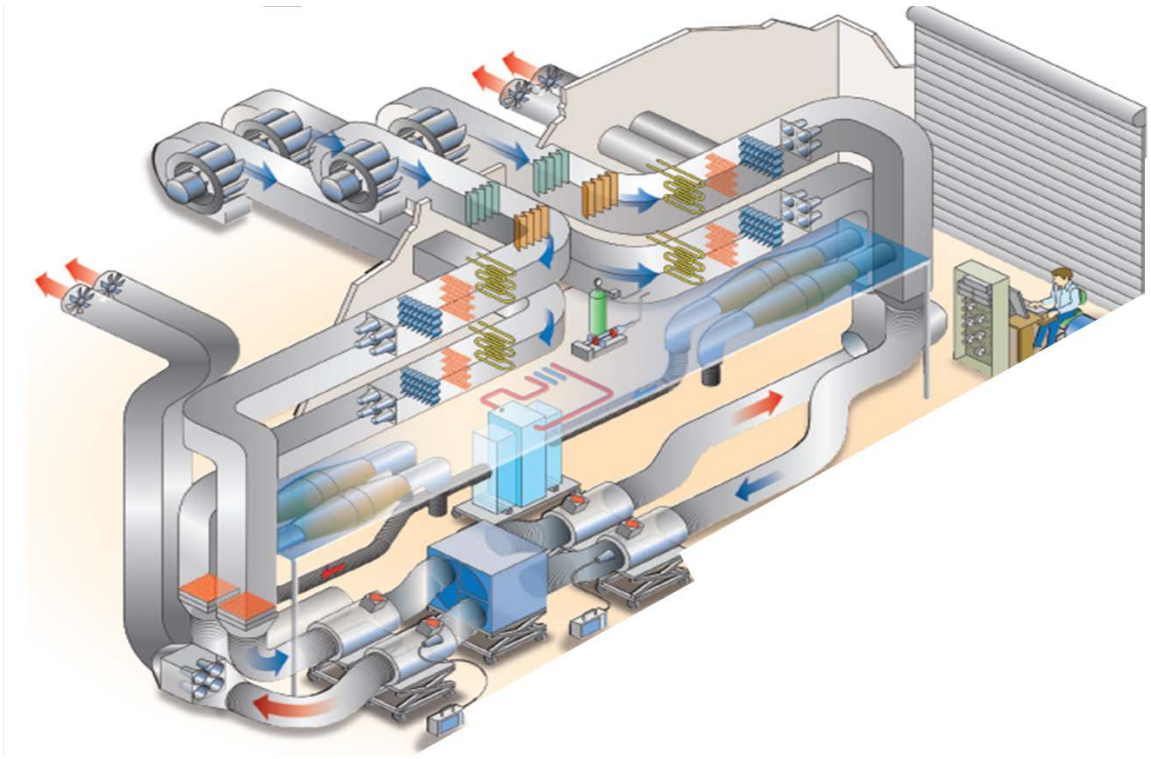

Figure 1. TTF laboratory containing four inlet and outlet airstreams

Figure by NREL

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Generally, testing methods and laboratory measurements are guided by ASME, ANSI, AHSRAE and AHRI standards. Although this project foundationally followed these standards, it did not strictly conform to them. For example, standards ANSI/ASHRAE 37 (ASHRAE 2019) and AHRI 210/240 (AHRI 2023) provide a framework for testing that result in a single rating value such as seasonal energy efficiency ratio (SEER) or heating seasonal performance factor (HSPF). Although these single point ratings provide a good comparative metric for consumers, they are insufficient for characterizing the equipment performance over a range of operational conditions, which is needed in building energy simulation.

2.1 Laboratory Setup

Providing precise and constant temperature and humidity conditions to the indoor and outdoor unit is essential for steady-state performance evaluations. Prior to collecting performance data, NREL test engineers ensured steady-state operation was achieved by monitoring in real-time the psychrometric conditions supplied to the indoor and outdoor.

Custom plenums were built around the indoor unit (air-handler) and connected to the laboratory's air streams. The TTF can generate and supply directly a wide range of psychrometric conditions to characterize the indoor unit. The laboratory fans assist the air-handler and provide conditioned air, at the proper volumetric flow rates and external static pressures during experimentation.

The lab can also generate a wide range of hot and humid psychrometric test conditions to characterize the outdoor unit in cooling mode. However, the existing TTF setup cannot directly supply the outdoor test article the extremely cold air conditions needed to replicate Chicago winters. Consequently, the NREL team had to design and build a custom environmental chamber to allow heating cycle evaluations that mimic Chicago's low ambient winter conditions. The heat pump outdoor unit, situated inside the environment chamber, would assist cooling the chamber to extremely cold conditions. The cold air leaving the outdoor unit would be recirculated until the desired cold test conditions were reached. Once the cold temperature was achieved, the TTF would trim the setpoints by adding heat or humidity to maintain steady-state conditions throughout the experiment.

The experimental design and setup for the indoor and outdoor will be discussed in the following subsections.

2.1.1 Indoor Unit

The test article's indoor unit comprises a refrigerant coil that provides heating or cooling, a thermal expansion valve, a variable-speed electronically commutated blower motor, and a control board as seen in Figure 2. In the pictured configuration, the blower draws air from the bottom of the cabinet through the refrigerant coil. The conditioned air then passes through the blower where it exits the top of the cabinet and provides supply air to the building. This cabinet allows for the condensate drain pan to be moved so the air-handling unit can be oriented horizontally or vertically.

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Figure 2. Internal view of the Carrier Infinity Series (FE4A) indoor unit (air-handler)

All photos by Greg Shoukas, NREL

The air-handler is mounted on top of insulated plenums such that the air, guided by turning vanes, makes a 90° turn at the cabinet's inlet and outlet. This method has been validated from prior research projects (Wheeler and Pate 2016). The TTF supplies and exhausts air across the indoor unit through 18-inch flexible ducts that are connected and clamped to the round collars. The indoor unit test setup can be seen in Figure 3.

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Figure 3. Air-handler (indoor unit), test article mounted on inlet (bottom) and outlet (top) plenums

A set of four static pressure taps are installed in each of the plenums to measure the external static pressure across the unit using a differential pressure transducer. Air blenders are installed in the inlet and outlet plenums to blend the air for a homogenous temperature measurement using an averaging array of thermocouples (TC) (ANSI/ASHRAE, 41.1-2013). An air sampling rake draws from each of the air streams to measure dew-point using chilled mirror hygrometers (ANSI/ASHRAE, 41.6-2014). Inlet and outlet air mass flow rates are measured using ASME flow nozzles, a thermocouple, and two differential pressure transducers with a combined uncertainty of less than 2% compliant with ANSI/ASHRAE, 41.2-2018. The indoor unit blower speed is measured using an optical tachometer mounted inside the air-handler and positioned to view the rotating fan cage. The indoor unit control board is connected to the outdoor unit control

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board and a Carrier Infinity Touch communicating thermostat. The thermostat communicates with both units to provide cooling or heating at the proper speeds. Further explanations of the thermostat are discussed in Section 3.

2.1.2 Outdoor Unit

The Carrier outdoor unit is composed of four main components: a variable-speed electrically commutated fan, an outdoor refrigerant coil, a variable-speed scroll compressor, and a variable frequency drive (inverter). This is shown in Figure 4.

Figure 4. Outdoor unit, test article

Image from Carrier (Carrier Corporation, 2018)

During operation, the outdoor unit's variable-speed fan draws air through the coil from four sides and exhausts it from the top of the unit. The fan speed is determined based on the outdoor air temperature. The variable-speed compressor moves refrigerant in a closed loop through the coils of the indoor and the outdoor units. Depending on whether the system is in heating or cooling mode, the coils either extract or reject heat between the refrigerant and air. The inverter modulates the speed of the compressor to match the equipment capacity with space-conditioning load. As a result, the unit runs nearly continuously while using the minimum amount of power to meet the setpoints. This strategy allows variable-speed heat pumps to provide consistent comfort and energy savings over traditional single-speed HVAC systems, which cycle their operation causing higher fluctuations in indoor air temperature. The system's inverter controls the compressor to higher speeds during the heating mode (compared to cooling mode) to compensate

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for loss of heating capacity without having to oversize the cooling capacity. Especially in cold climate zones, this is a major advantage over single-speed heat pumps because the heating requirements determine system size.

An insulated, custom environmental chamber was designed and built to conduct experimentation of the heat pump under a wide range of outdoor air conditions (Figure 5). Psychrometric conditions supplied to the inlet of the test article are controlled by mixing makeup air provided by the TTF and recirculation air from the exhaust of the outdoor test unit. The mixing takes place in the return plenum of the environmental chamber.

The proper makeup air flow rate, required to achieve the desired psychrometric (temperature and humidity) conditions at the outdoor unit inlet, is managed through a set of two dampers labeled in Figure 6. One damper allows a fraction of makeup air into the return plenum, while the second damper bypasses the excess makeup air to the TTF exhaust air stream. A booster fan draws air from the exhaust plenum and mixes it with the makeup air before returning it to the heat pump.

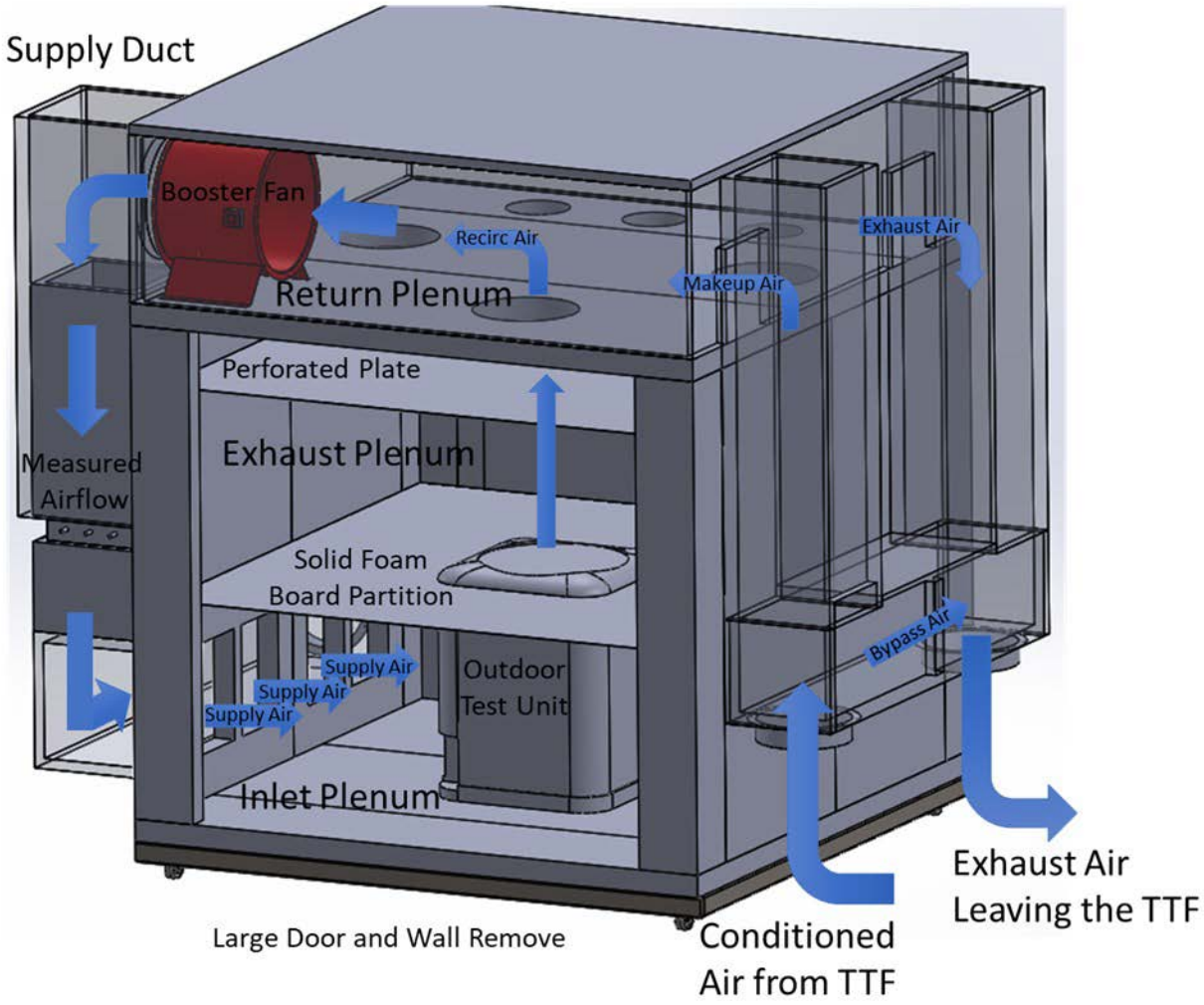

Figure 5. Environmental test chamber used to create an outdoor climate around the test article

All remaining report figures by NREL

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In heating mode, recirculating the cold exhaust air from the outdoor unit lowers the temperature inside the chamber and allows it to be cooled to subzero temperatures. In cooling mode, recirculating the hot exhaust air from the outdoor unit raises the temperature inside of the chamber. To maintain a constant temperature in the chamber during heat pump experimentation, the lab exhausts a portion of the recirculated air and provide counteracting warm or cool makeup air. Similarly, humidity levels are controlled at the heat pump inlet by adjusting the humidity ratios in the makeup airstream. This control strategy maintains constant psychrometric inlet conditions during heat pump characterization for both heating and cooling modes. This technique also allows operation at temperatures below that required by AHRI standard 210/240.

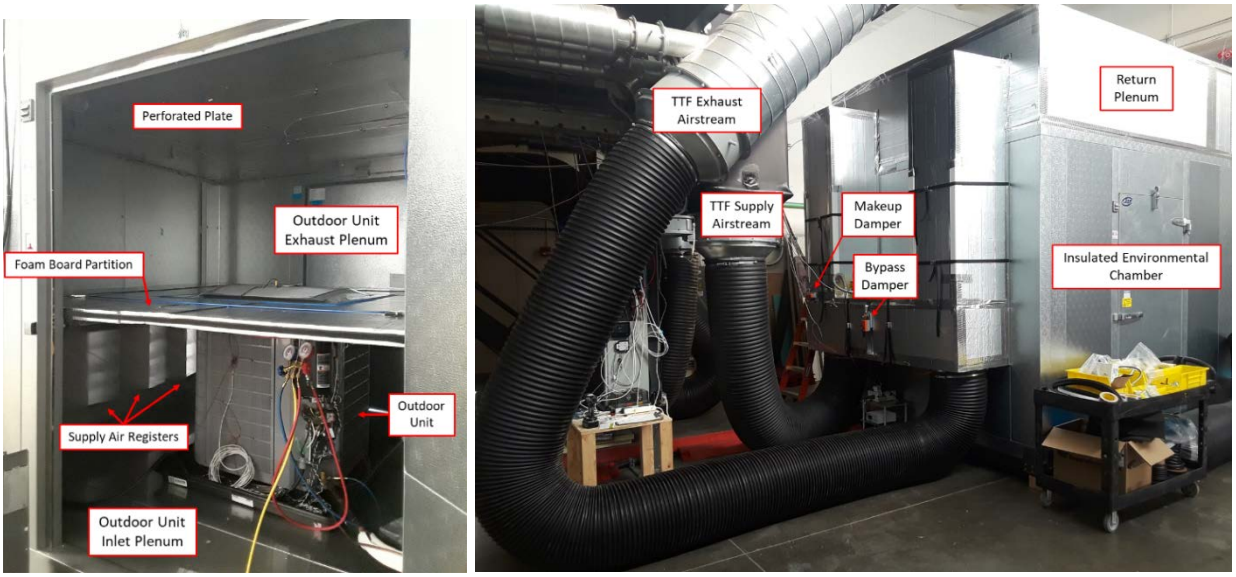

Figure 6. Outdoor unit set inside environmental chamber (left); environmental chamber connected to the TTF airstreams (right)

Temperature, humidity, static pressure, and air flow measurements are taken at various points in the environmental chamber. Characterizing the inlet and exhaust, temperature, and dew-point conditions provides information related to the enthalpy exchange from the outdoor unit. Furthermore, these measurements provide the laboratory feedback information needed to adjust and condition the makeup air. The volumetric air flow rate supplied to inlet plenum via the booster fan is measured through an averaging pitot tube array.[1] Prior to testing, the pitot tube array measurements were calibrated using the TTF flow nozzles readings to ensure the precision in the recirculation air flow values. The static pressures measured in the inlet and outlet plenum allow the laboratory to control the fan speed and air flow rates to the desired experimental conditions.

[1] https://www.dwyer-inst.com/Product/AirQuality/FlowSensors/SeriesFLST#literature

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2.2 Measurement and Instrumentation Plan

Overall, the measurement and instrumentation plan served the following two main purposes:

1. Collect data required to quantify the heat pump's capacity, power consumption, and performance
2. Provide feedback information related to the response of the laboratory, environmental chamber, or the test article.

Feedback measurements are needed to make dynamic controls adjustments to achieve stable, steady-state test conditions. The essential measurements will be discussed individually in the following sections. A complete instrumentation list including the critical measurements and sensors configured in the data acquisition and controls system can be found in Appendix A, Table 13.

2.2.1 Power

Electrical power is measured with industrial, revenue-grade power meters. A power meter requires two measurements, voltage and current. A total of three power meters were used during the heat pump laboratory experiments to monitor the power consumption of the indoor unit, the outdoor unit, and the outdoor unit fan. The difference between the total outdoor unit power and the fan power yields the power input to the inverter, which drives and modulates the compressor speed. Table 2 provides information about the power measurements.

Table 2. Power Measurement Sensors

Model Number	Distributor	Measurement Description
Acuvim II-D	Accuenergy Inc.	Voltage, energy, power
Accu-CT	Continental Controls	Current transducer

2.2.2 Air Flow Rate

Volumetric air flow in the TTF airstreams is measured using in-duct nozzles and two differential pressure measurements. NREL uses American Society of Mechanical Engineers (ASME) low-beta flow nozzle arrays. In addition, temperature, dew-point, and barometric pressure measurements are required to determine the air properties such that volumetric air flow can be converted to mass flow rate.

The combined uncertainty of the nozzle box and the associated instruments results in ±2% accuracy in mass flow rate measurements (ANSI/ASHRAE Standard 41.2-2018). Nozzle boxes measure the mass flow rate at the inlet and outlet air stream connected to the indoor unit and the makeup and exhaust air stream of the environmental chamber.

In addition, a custom sized, averaging pitot tube array (air measurement station) is designed in the supply/recirculating ductwork of the environmental chamber. The air measurement station and differential pressure transducers are calibrated using the lab flow nozzles. Table 3 provides information about the air flow measurement sensors.

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Table 3. Air Flow Rate Measurement Sensors

Model Number	Distributor	Measurement Description
TTF Laboratory Nozzles	NA	Air mass flow rate
FLST-R-18x20	Dwyer Instruments Inc	Air flow (velocity) measurement station
607-01	Dwyer Instruments Inc	Differential (air) pressure transducer
607-21	Dwyer Instruments Inc	Differential (air) pressure transducer

2.2.3 Capacity

ASHRAE 37 (ASHRAE 2019) specifies a primary and secondary set of mass-energy measurements for determining the cooling and heating capacity of the test article. Both sets of measurements are required to be at or less than 6% of agreement. The primary cooling/heating capacity measurements are based on air-enthalpy method and are taken across the indoor unit. The measured inlet and outlet air temperature, humidity, and air mass flow rate are used to determine the enthalpy change of the air across the cooling/heating coil. Table 4 provides information about sensors used for air-enthalpy measurements. Air-enthalpy method can also be taken across the outdoor unit, although these values have higher uncertainty due to:

- Lower accuracy of the air measurement station
- Extremely low dew-points that exceed the limit of the hygrometers, particularly when the chamber is operated at subfreezing conditions.

Table 4. Heating/Cooling Capacity Measurement Sensors

Model Number	Distributor	Measurement Description
TTF Laboratory Nozzles	NA	Air mass flow rate
Type-T, TC Wire Array	Omega Engineering Inc	Air temperature
SIM-12H	General Eastern	Dew-point hygrometer

Secondary cooling/heating capacity measurements are made based on refrigerant enthalpy method. This methodology relies on mass energy balance of refrigerant across cooling/heating coil. In addition to refrigerant mass flow rate, refrigerant temperature and pressures measurements will be used to quantify the thermodynamic properties of the refrigerant. The refrigerant flow meter measurements only provide accurate results when the refrigerant is in a pure liquid phase and therefore cannot always be relied upon. A sight-glass was placed in the refrigerant line to provide a visual indication of the state of refrigerant. Table 5 provides information about the sensors that were used to establish refrigerant mass energy balance.

Table 5. Heating/Cooling Capacity Measurement Sensors

Model Number	Distributor	Measurement Description
Elite Series CMF025	Micro Motion	Mass flow rate
Type-T, Adhesive Pad TC	Omega Engineering Inc	Surface temperature
PX309-1KG5V	Omega Engineering Inc	Pressure
Baratron 220D	MKS Instruments	Barometric pressure

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2.2.4 Feedback Measurements and Test Loop Instrumentation

In addition to power, air flow rate, temperature, and relative humidity measurements, various additional sensors are required to perform these experiments. These measurements are important to determine the test article response and provide feedback controls for stable laboratory operation. Furthermore, these measurements are used to make calculated corrections to the performance data in postprocessing. Due to testing at altitude in Golden, Colorado (5,865 ft above sea level), the measured performance data represents the equipment operation in a lower, air density ("thin-air") environment whereby standard air pressure is 0.817 bar. Postprocessing data for thermodynamic and power corrections are required to adjust the high-altitude performance to the expected heat pump performance as if operating at sea level conditions. Table 6 lists information about the additional sensors that were used. A description of the methodology is described by Wheeler et al. (2018).

Table 6. Additional Measurements and Sensors

Model Number	Distributor	Measurement Description
239	Setra Systems Inc	Differential (air) pressure transducer
Type-T, TC Probe	Omega Engineering Inc	Dry-bulb temperature
DPS3	Edgetech Instruments	Dew-point hygrometer
ACT-3X/ROLS-W	Monarch Instrument	Optical tachometer (fan speed)
IMFA0035	Red Lion	Frequency counter (compressor speed)
DCT-0010-005	Aim Dynamics	Current transducer (defrost on/off detection)
Baratron 220D	MKS Instruments	Barometric pressure

3 Experimentation Plan

This section describes experimentation approach and the methodology used to develop equipment performance curves for EnergyPlus simulation platform. Enhancing the EnergyPlus building simulation library with performance data of the test article was the primary driver for developing the experimentation plan. EnergyPlus models simulate building and HVAC performance in various climates by using short (typically 15-minute) timesteps integrated into hourly and annual predictions. The simulations account for dynamic hourly interactions between building thermal loads, equipment performance, and weather. Simulation outputs include but are not limited to energy consumption, electric demand, building heating and cooling loads, and equipment capacity.

Performance mapping the heat pump over a wide variety of psychrometric conditions will provide the required model inputs to simulate annual building energy consumption. During performance mapping, obtaining performance data across a wide range of independent variables is more important than the need to gather data at any specific test condition. Wide ranges of data collection ensure that the developed performance regressions used to underpin the EnergyPlus model remain valid even during extreme design heating/cooling days.

The following subsections describe the systematic approach followed in the project to develop performance mapping of the equipment:

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Section 3.1: Run the test article under varying conditions to better understand its embedded controls and operational limits.

Section 3.2: Develop a design of experiment that vary critical parameters and characterizes the equipment performance over its expected range of operation.

Section 3.3: Adjustments required to transform the high-altitude data to heat pump performance at sea level conditions.

Section 3.4: Characterize the equipment performance at each of the design of experiment conditions.

Section 3.5: Curve fit the performance data into regression models to extrapolate between test conditions.

3.1 Embedded Controls and Limits of Operation

The performance of vapor compression air conditioning (and heat pump systems) varies continuously depending on the sensible (temperature) and latent (humidity) loads on the indoor and outdoor units. Traditional, constant-speed, split air-conditioning systems operate the compressor, outdoor, and indoor fans at full speed when providing heating or cooling, despite the building's varying thermal load. These units undergo frequent on/off cycling to meet the thermostat setpoint. The on/off cycling maintains a building temperature that oscillates significantly above and below the temperature setpoint.

Variable-speed systems can modulate the indoor fan, outdoor fan, and the compressor to match the equipment capacity to the varying building loads. As a result, these units run continuously while using the minimum amount of power to provide heating or cooling. This strategy provides superior levels of comfort due to negligible space temperature fluctuations and energy savings over traditional single-speed HVAC systems.

Variable-speed systems have numerous sensors and embedded controls to optimize the efficiency and performance. The controls also ensure equipment longevity by limiting the operational ranges within the physical constraints of the equipment. Understanding these boundaries is essential to properly design an experimentation matrix that allows for data collection over a wide range of conditions within the operational range of the equipment.

3.1.1 Variable-Speed Compressor

Performance mapping a constant-speed system requires monitoring system operation as a function of varying indoor/outdoor temperatures and humidity conditions. This requirement is equivalently applicable to performance mapping variable-speed systems; however, the evaluation is more extensive due to the complexity of determining the conditioning capacity and performance at various compressor speeds. As the building's heating or cooling load changes, the heat pump modulates its compressor speed to match the space-conditioning needs.

Prior to developing a design of experiment, the equipment was run over a wide range of conditions to determine the operating boundaries. This ensured the broad range of test points were within the operational limits. Laboratory observations and measurements determined the

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minimum and maximum compressor speeds are primarily limited as a function of the outdoor air temperature. This is sensed by a thermistor mounted on the outdoor unit. Additionally, in heating mode, the thermostat setting (comfort or efficiency mode) puts secondary limits on the maximum compressor speed.

Although the system can operate beyond the outdoor temperatures plotted in Figure 7 and Figure 8, it represents the temperature range of the test matrix. In cooling mode, the compressor minimum and maximum speed limits are the same for comfort mode and efficiency mode. In heating mode, the minimum compressor speeds are the same for comfort mode and efficiency mode, but the two modes have different maximum compressor speed limits, as shown in Figure 8.

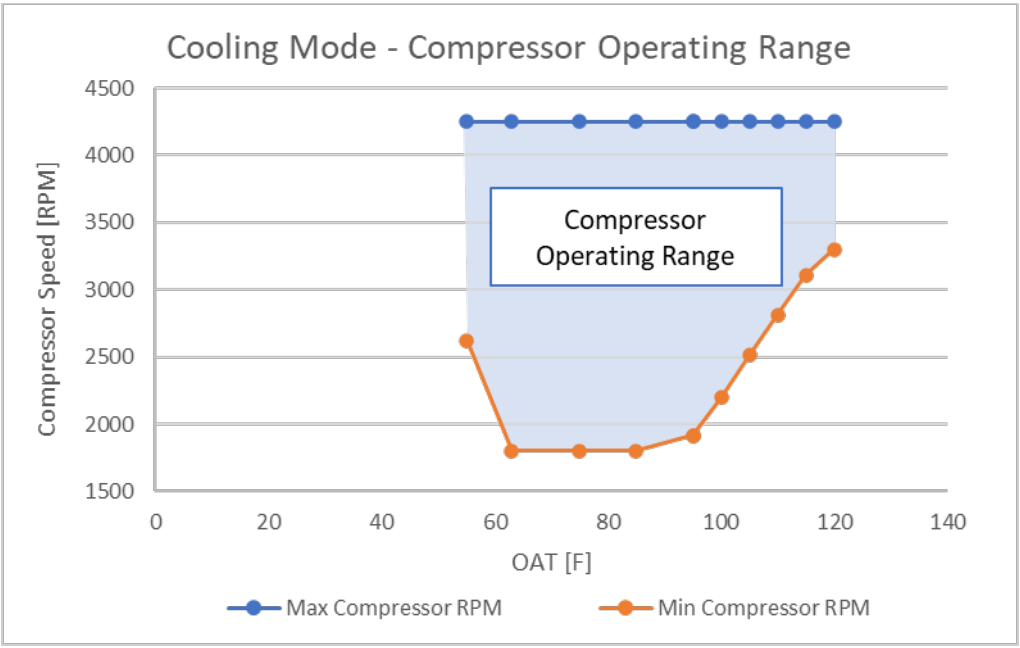

Figure 7. Variable speed limits when the compressor operates in cooling mode

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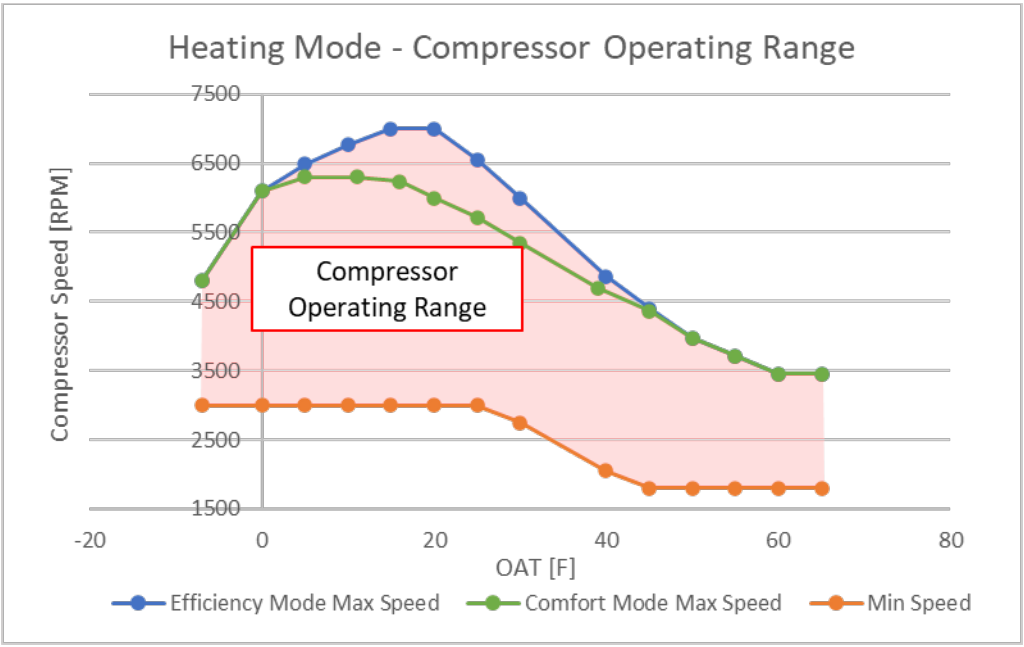

Figure 8. Variable speed limits when the compressor operates in heating mode

3.1.2 Thermostat Modes

The heat pump thermostat can operate the equipment in four general modes: technician checkout, comfort, efficiency, and maximum. Depending on the thermostat mode, the indoor unit fan speeds are controlled differently as the compressor speed varies. These differences in the thermostat's mode of operation have implications on the exiting supply air state, the conditioning capacity, and energy consumption.

Technician checkout mode is required on all variable-speed HVAC equipment. This is primarily used for third-party AHRI 210/240 (AHRI 2023) test rating and certification (SEER and HSPF). In this mode, a technician can force the unit to operate at a user-specified compressor speed between 50% and 100% of full capacity. The indoor fan speed operates according to the capacity setting. Although this mode of operation provides the easiest means to modulate the compressor speed during testing, it is unclear if this mode of operation represents the heat pump's behavior under the other three "normal" thermostat control modes. While the project initially observed and compared the heat pump operation in technician checkout, comfort, and efficiency modes, it was concluded that the results were difficult to interpret due to inconsistency in the equipment operating speeds under various indoor and outdoor temperatures. To characterize the equipment most accurately in its typical modes of options, both comfort and efficiency modes were evaluated separately to capture performance differences.

Comfort mode is the default thermostat setting. As implied, the heat pump operates to prioritize occupancy comfort. When set to provide cooling, the air-handler fan speed operates at a relatively low flow per thermal capacity (cfm/ton), which provides better dehumidification. The thermostat measures and considers both the space temperature and indoor humidity when determining the supply air flow rate. The range of air-handler unit flow rates for the two modes of operation can be seen in Figure 9.

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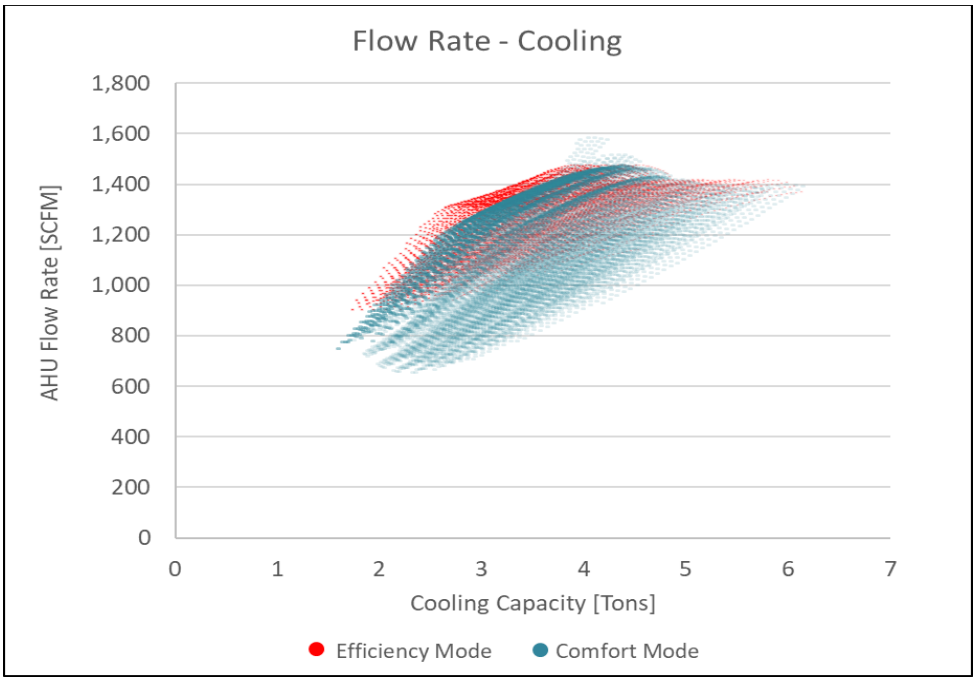

Figure 9. Air-handler unit flow rates for two modes of cooling operation; data points represent the performance lookup table generated across a broad range of indoor and outdoor conditions

Although additional thermostat settings are available to provide further dehumidification control, these were not adjusted, and the default values were used. When the heat pump is set to provide heating in comfort mode, the humidity measurement is neglected. During heating, comfort mode maintains lower air-handler unit flow rate to provide a higher supply air temperature than in efficiency mode (Figure 10). Independent of the mode of operation and under extremely cold outdoor air temperatures, the heat pump will require auxiliary heating due to the dramatically lower supply air temperatures (Figure 11).

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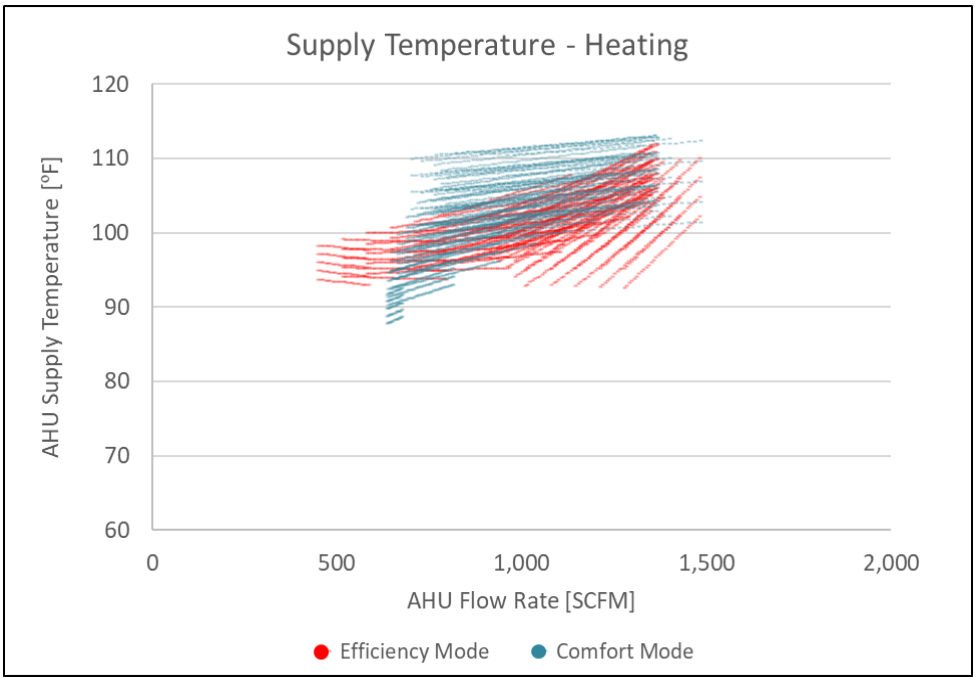

Figure 10. Air-handler unit supply air temperature for the two modes of heating operation; data points represent the performance lookup table generated across a broad range of indoor and outdoor conditions

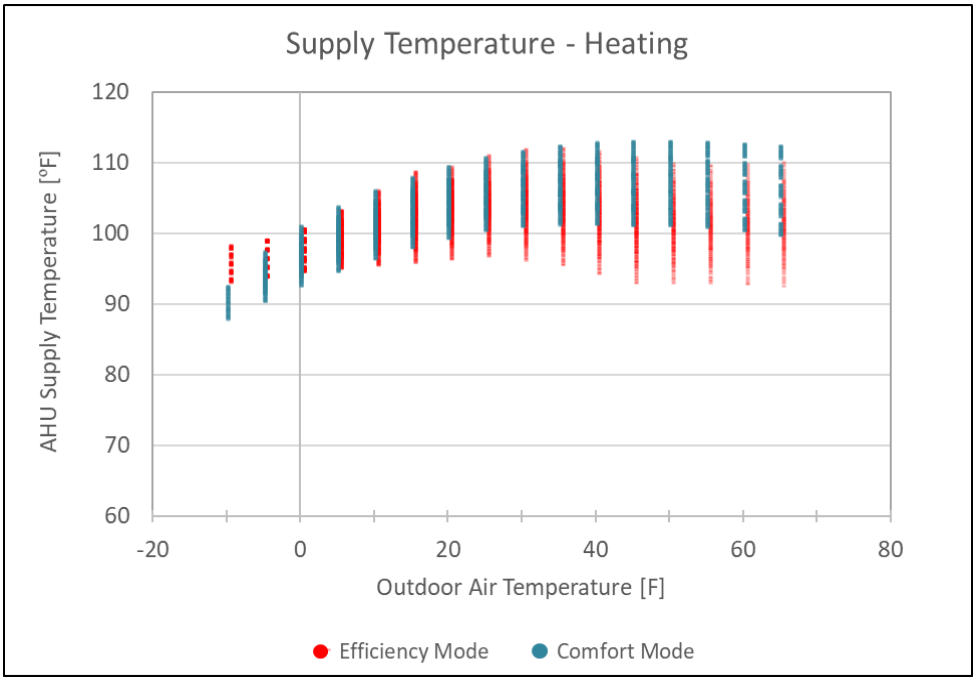

Figure 11. Supply air temperatures with respect to the outdoor air temperature and mode of operation based on the performance lookup table

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Efficiency mode operates the equipment to prioritize energy savings. During space cooling, a faster fan speed increases the sensible heat ratio (SHR) such that sensible efficiency is improved, but at the detriment of latent capacity. When providing space heating, a faster fan speed improves heating efficiency but reduces supply air temperature, which some people perceive as uncomfortable. Figure 8 also shows that the compressor can operate at higher speeds. This boost in capacity allows the outdoor unit to extract more heat from the outside air, presumably at increased efficiency.

Because the focus of the project was to ascertain the energy efficiency benefits of the test article, we decided to eliminate the max mode (fourth mode of operation) from the experimentation plan. Additionally, this low-priority evaluation would have increased the number of experimentation permutations and complexity.

All other thermostat settings remained as the factory default values. Additional information on the numerous functions, settings, and features of the thermostat (SYSTXCCITC01-B) can be found by referencing the user manual.

3.2 Design of Experiment

Performance mapping the heat pump requires a wide combination of factors to be varied. These independent variables affect the equipment capacity and energy consumption. Due the vast number of combinations that result from the independent variables, a full-factorial test matrix would not be practical. Instead, the use of a statistical software package, JMP® from SAS®, was used to develop a custom design of experiment. The software determines a test matrix, guided by classical design of experiment principles, which significantly reduces the number of test combinations needed to develop low-uncertainty response surface methodology regressions. The independent inputs and specified ranges needed to develop the cooling and heating test matrix are explained in the following sections.

3.2.1 Cooling Mode

The factors that affect the capacity, performance, and energy consumption of a heat pump in cooling mode are the outdoor dry-bulb air temperature, the indoor dry-bulb return air temperature, the indoor return air wet-bulb air temperature (humidity), and the speed of the compressor and fans.

Instead of specifying the indoor humidity as a wet-bulb temperature, the test matrix captures this factor using dew-point depression. The dew-point is a measure of the absolute humidity or water vapor present in the air. The dew-point depression is a delta temperature that is subtracted from indoor dry-bulb temperature, resulting in the dew-point temperature.

Two designs of experiments were developed to characterize the indoor unit under high humidity (relatively small dew-point depressions) and low humidity (large dew-point depressions) conditions. These tests are respectively designated as a wet-coil conditions and dry-coil conditions. The wet-coil conditions assess the performance of the system when the indoor unit provides both latent (dehumidification) and sensible cooling. Under these conditions, water vapor is removed from the air and condensate forms on the cooling coils. The dry-coil conditions assess the indoor coil performance when no dehumidification occurs. When the dew-point depression is sufficiently large, the moisture content of indoor air is very low. Under these

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conditions, dehumidification cannot occur because the evaporator coil temperature is above the indoor airstream dew-point. This results in a system that provides exclusively sensible cooling capacity.

Last, the operation of the unit in comfort mode and efficiency mode were also characterized. This again doubled the number of tests performed to provide an extensive understanding of the equipment performance. The factors and the specified range for which the design of experiment was developed to performance map the heat pump in cooling are shown in Table 7. The explicit matrix of wet-coil and dry-coil test conditions can be found in Table 14 and Table 15 in the Appendix.

Table 7. Factors and Ranges Specified to Develop the Cooling Design of Experiment Test Matrix

Independent Variable	Type of Variable	Range: Wet-Coil	Range: Dry-Coil
Outdoor dry-bulb air temperature	Continuously varied	55° to 120°F	55° to 120°F
Indoor return air dry-bulb temperature	Continuously varied	68° to 82°F	68° to 82°F
Indoor return air dew-point depression temperature	Continuously varied	5° to 25°F	>35°F
Compressor speed [4]	Continuously varied	1,850 to 4,250 RPM	1,850 to 4,250 RPM
Thermostat mode	Discretely varied	Comfort, efficiency	Comfort, efficiency

[4] The compressor speed is bounded by its operational limits shown in Figure 7.

3.2.2 Heating Mode

The factors that affect the capacity, performance, and energy consumption of a heat pump in heating mode are the outdoor dry-bulb air temperature, the outdoor wet-bulb temperature (humidity), the indoor dry-bulb return air temperature, and the speed of the compressor and fans.

In heating mode, the air-handler indoor coil acts as the refrigerant condenser where the superheated, high-pressure, refrigerant gas exchanges heat with the space return air blowing over the coils. The coils of the outdoor unit act as the evaporator where the expansion of high-pressure liquid refrigerant extracts heat from the outdoor air. Depending on the outdoor moisture content, frost formation can occur on the outdoor coil when the saturated refrigerant temperature is lower than the outdoor air dew-point. Under these conditions, the water vapor from the air freezes on the outdoor coil resulting in degradation of heat transfer.

Consequently, elimination of frost is important to maintain heat transfer effectiveness across the outdoor coil. Therefore, periodically the unit initiates defrost cycles, which temporarily reverses the operation of the equipment similar to a cooling cycle. At outdoor temperatures below 50°F, the heat pump enables defrost cycles to keep the outdoor coil free of frost and ice. Although the defrost cycle is essential for reliable heating operation, this poses two detrimental impacts: 1) energy is consumed to defrost the coil instead of heating the building, and 2) heat already supplied to the space by the heat pump is removed from the building and used to defrost the outdoor coil. This results in cold air being blown through the building supply ducts.

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A defrost cycle can last between 3.5 and 10 minutes. During this time, heat from the space is absorbed in the refrigerant through the indoor unit coil and rejected to the outdoor coil to melt the frost. This is a parasitic process that removes heat from the indoor space and uses the heat pump energy solely to melt the ice. The defrost cycle frequency and duration are dependent on the thermostat settings. By default, the system is set to defrost "automatically." Detailed information related to the manufacturer's automatic defrost control logic and the defrost time intervals can be found in Figure 27 in the Appendix.

Elevated outdoor dew-point temperatures result in frost formation and frequent defrost cycles which add complexity to steady-state performance mapping the system in heating mode. Two designs of experiments were developed to characterize the heating performance. The first test was designed to assess the heating capacity and energy consumption of the heat pump under (relatively) frost-free conditions. The second test was designed to analyze the heating capacity and COP degradation over long operating periods of operation. Through these experiments, the performance degradation due to frost formation was characterized and energy penalty from defrost cycle was quantified.

The heat pump performance was first characterized under low humidity conditions during which the coil developed minimal frost. The goal was to replicate a dry-coil, steady-state heating test when no dew (or frost) would form on the outdoor unit coils. To minimize defrost cycle interruptions and allow sufficient time for steady-state performance to be achieved, the thermostat defrost setting was increased to the maximum, 120-minute, time interval. Additionally, no humidity was added to the test chamber via the laboratory air streams, which reduced the rate of frost buildup. Because these tests were performed during the month of April in Golden, Colorado, the makeup air dew-point supplied by the laboratory naturally ranged from -12ºF to -4ºF. This imposed the lowest humidity conditions achievable on the outdoor unit. Minimizing the humidity levels during testing represents the highest achievable, steady-state performance data due to a dry and frost-free coil.

The variables and ranges for which this design of experiment was developed to characterize the heating performance are shown in Table 8. Not all combination of the ranges could be reached in the environmental chamber. For example, the -7ºF outdoor air condition created inside the test chamber was only achievable at the maximum compressor speed and the minimum indoor return-air temperature. The explicit matrix of steady-state test conditions can be found in Table 16 in the Appendix.

Table 8. Factors and Ranges Specified to Develop the Steady-State Heating Design of Experiment Test Matrix

Independent Variable	Type of Variable	Range
Outdoor dry-bulb air temperature	Continuously varied	-7º to 60ºF
Indoor return air dry-bulb temperature	Continuously varied	60º to 76ºF
Compressor speed [4]	Continuously varied	1,800 to 7,000 RPM
Thermostat mode	Discretely varied	Comfort, efficiency

[4] The compressor speed is bounded by its operational limits shown in Figure 8.

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A second set of tests was performed to better understand the heating capacity degradation and increased energy use as frost forms. These tests operate the heat pump at the minimum or maximum heating capacity, at a constant outdoor air temperature and high humidity levels, for extended periods of time (8 to 12 hours). Over time, as frost accumulates on the coil, the heat transfer effectiveness decreases. The gradually decreasing heating capacity results in longer compressor runtimes to meet the thermostatic setpoint. Integrating the degrading heating capacity and varying energy usage between and during defrost cycles characterizes an average capacity and COP. The heating performance under defrost periods was compared with the ideal steady-state, dry-coil performance to estimate degradation factors. All tests were run with the thermostat set in comfort mode with the assumption that the derating factors, based only on compressor speed and outdoor air temperature, can be applied in efficiency mode. During these experiments, the thermostat was programmed to the default "Auto" defrost setting. The automatic defrost control logic is explained in the Carrier service manual and included in Figure 27 in the Appendix.

3.3 Testing Adjustments and Measured Performance Corrections

Equipment performance at sea level conditions is desired for EnergyPlus simulations. The lower air density due to NREL's location at 5,865 feet above sea level skews the experimental results. Therefore, corrections were made during experimentation and during data postprocessing to adjust the measured performance at altitude to what is expected at sea level. The following sections will discuss those adjustments.

3.3.1 Outdoor Unit Fan Flow

The axial fan on the outdoor unit of the heat pump is driven by an electrically commutated motor (ECM) to provide variable-speed fan operation. The volumetric flow rate drawn through the outdoor unit coils by the fan is directly proportional to its rotational speed. The volumetric flow rate versus fan speed is correlated from measurements taken by the averaging pitot tube array and an optical tachometer. From this relationship, the volumetric flow rate is known solely based on the fan speed.

The lower ambient air pressure experienced at altitude results in lower air density. For the same volumetric flow rate at sea level, the lower air density at altitude results in approximately 20% less mass flow rate through the outdoor coil. Therefore, the mass flow rate of the thin-air through the test article must be increased to ensure an equivalent heat transfer rate at sea level. This is accomplished by assisting the outdoor unit fan and drawing additional volumetric flow through coils using the environmental chamber booster fan. The outdoor fans volumetric flow rate, correlated to its rotational speed in RPM, is boosted dynamically during testing by the ratio of the ambient air pressure (or density) at sea level and altitude expressed in Equation 1.

$$\dot{V}_{SL} = \dot{V}_{alt}(RPM) * \frac{P_{amb,SL}}{P_{amb,alt}} \quad (1)$$

This correction was applied to all steady-state cooling tests. The flow boost was also applied to the steady-state heating tests at outdoor air temperatures above 18ºF. Temperatures lower than 18ºF showed no additional heat transfer rate when the flow was increased, and no air mass flow boosting was applied.

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3.3.2 Outdoor Unit Fan Power

The lower density air results in reduced electrical fan power measurements at altitude. To properly account for the overall efficiency of the heat pump at sea level, corrections to the measured electrical fan power must be adjusted when postprocessing the data.

The outdoor unit hydraulic fan power and power consumption are governed by the volumetric air flow rate, the static pressure, and the fan/motor efficiency. The volumetric flow rate is a function of the fan speed. However, at sea level, the fan power will increase as more static pressure is imposed on the fan due to the denser air. Assuming a constant fan/motor efficiency, the fan power (measured under thin-air conditions) can be adjusted by the ratio of the ambient pressures of sea level and altitude. Prior to running performance tests, a correlation was developed to characterize the (thin-air) electrical power consumption of the outdoor unit fan versus the fan speed. The measurements, shown in Figure 12, were taken using an Acuvim power meter and an optical tachometer. Identical measurements were also taken in heating operation, which generated a slightly different correlation.

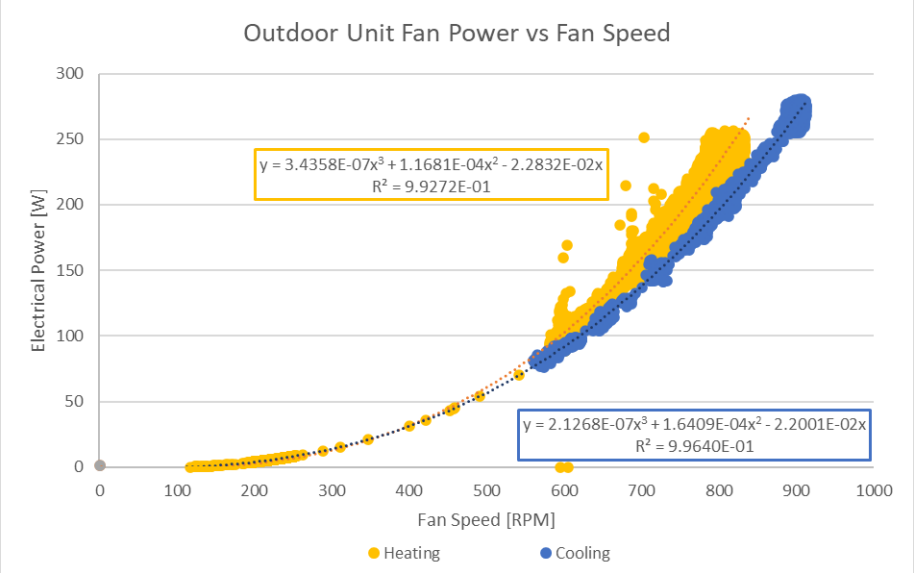

Figure 12. Electrical power consumption of the outdoor fan unit relative to fan speed

All steady-state performance data were postprocessed to apply the fan power corrections and adjust for sea level air density. Also shown in Figure 12, the expected outdoor fan power in cooling and heating operation are represented by the empirical equations 2 and 3 below. The measured fan power during testing was subtracted from the total system power and the corrected fan power substitutions were added.

$$\dot{Q}_{fan,SL} = [(2.127 * 10^{-7}) * (RPM)^3 + (1.641 * 10^{-4}) * (RPM)^2 - (2.200 * 10^{-2}) * (RPM)] * \frac{P_{amb,SL}}{P_{amb,alt}} \quad (2)$$

$$\dot{Q}_{fan,SL} = [(3.436 * 10^{-7}) * (RPM)^3 + (1.168 * 10^{-4}) * (RPM)^2 - (2.283 * 10^{-2}) * (RPM)] * \frac{P_{amb,SL}}{P_{amb,alt}} \quad (3)$$

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3.3.3 Indoor (Air-Handler) Fan Power

The air-handler fan, driven by an electrically commutated motor, varies the fan speed to meet a predetermined standard volumetric flow. This is based on the equipment's operating heating or cooling capacity, a user altitude input in the thermostat, and the measured external static duct pressure imposed on the fan. The controls calculate and set the fan speed to deliver the exact standard cubic feet per minute of air flow knowing the manufacturers fan curves and monitoring the current draw. The flow rate can be displayed on the thermostat and the accuracy over a wide range of operation was confirmed to be within a few percent of the laboratory nozzle measurements. Whether at altitude or sea level, the system attempts to supply a standard volumetric flow rate. Two adjustments are made to accurately represent indoor unit fan power under testing.

The first adjustment is imposed dynamically during evaluation. The AHRI 210/240 (AHRI 2023) specifies that the air-handler must experience a maximum external static pressure (ESP) of 0.5 inches of water column (w.c.) at the maximum volumetric flow rate. This imposed resistance represents the fan power consumption as if it were installed in a ducted system at sea level. As the air-handler modulates to lower flow rates, the maximum ESP imposed on the fan is reduced by equation 4. The pressure imposed across the air-handler is measured by laboratory and adjusted with the laboratory inlet and exhaust fans.

$$\Delta P_{static,reduced\ flow} = \Delta P_{static,max\ flow} * \left(\frac{\boldsymbol{P_{amb,SL}}}{\boldsymbol{P_{amb,alt}}}\right) * \left(\frac{\dot{\boldsymbol{V}}_{reduced\ flow}}{\dot{\boldsymbol{V}}_{max\ flow}}\right)^2 \quad (4)$$

The second adjustment is performed when postprocessing the data to correct the measured electrical fan power to represent sea level conditions. For the air-handler to move the proper standard volumetric flow of air at altitude, the fan must spin faster to push more volume of the less dense air. The fan consumes more power by operating at higher speeds to move more of the less dense air and meet the standard volumetric flow rate requirement. The additional flow compounds further energy consumption, due to the higher internal static pressure generated across the cooling coil. Therefore, the fan consumes more electrical power than it would at sea level from the multiple facets of higher flow and higher internal static pressure. The measured electrical fan power must be adjusted and reduced by a ratio of the ambient pressures squared, as shown in equation 5. This correction was applied when postprocessing the test data in cooling and heating operation.

$$\dot{Q}_{fan,\boldsymbol{SL}} = \dot{Q}_{fan,alt} * \left(\frac{\boldsymbol{P_{amb,alt}}}{\boldsymbol{P_{amb,SL}}}\right)^2 \quad (5)$$

3.3.4 Sensible Heat Ratio (Cooling Only)

The total cooling capacity is composed of sensible and latent components. Sensible heat ratio is the ratio of sensible cooling to total cooling (sensible and latent). A sensible heat ratio of one represents a dry, indoor coil.

Under dry-coil test conditions, no dehumidification can occur. Therefore, the total cooling capacity goes exclusively to sensible cooling. For the identical refrigerant flow rate (or

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compressor speeds), no sea level cooling capacity corrections are required to adjust the data measured at altitude if a few conditions are met. The first condition is the air mass flow rate at altitude and sea level through the indoor and outdoor coil are equal. The second condition is that the inlet dry-bulb temperature and relative humidity stay the same. If these conditions are met, the dry-coil efficiency is identical between sea level and altitude because the effectiveness of a sensible, finned coil heat exchanger is solely dependent on the number of transfer units.

During wet-coil evaluation, mass transfer occurs when water vapor from the moist air stream condenses on surface of cold coil. Under wet-coil test, the sensible heat ratio requires a minor altitude adjustment to accurately represent the coil outlet conditions at sea level. The sensible and latent performance is adjusted by means of calculating the sea level supply air conditions that provide the same capacity and relative humidity as the test result (at altitude). This method maintains equal number of transfer units of the evaporator coil. This is also explained by Wheeler et al. (2018).

3.4 Characterizing the Equipment Performance

The test article was evaluated for cooling and heating performance under its two inherent control modes of operation—comfort and efficiency. As the temperature and humidity conditions vary, the unit will modulate the compressor speed, and outdoor and indoor fan speeds to provide appropriate space conditioning. The outdoor unit senses the ambient outside temperature while the thermostat measures the indoor space temperature and humidity. The controls programmed into the thermostat account for these factors to adjust the system speeds at a 1-minute interval. As the heat pump capacity modulates, the laboratory connected to the environmental test chamber responds accordingly to maintain constant conditions during experimentation. The execution of operating the laboratory and collecting the data will be described in the following sections.

3.4.1 Steady-State Cooling Mode Tests

The laboratory supplies the air at the desired test conditions to the indoor unit that represent a "return air" temperature and humidity. Air flow and pressure is also maintained across the indoor unit to maintain a prescribed external static pressure representative of ductwork per AHRI 210/240 (AHRI 2023). As the indoor unit fan changes speed, the laboratory controls dynamically adjust using a proportion, integral, derivative algorithm to maintain the proper setpoints.

The outdoor unit rejects the heat from the refrigerant to the air inside of the environmental chamber. The laboratory fans exhaust a small portion of the hot air and supply cool makeup air back into the chamber to ensure the environmental chamber air temperature remains constant during experimentation. Through a set of air flow dampers on the environmental chamber, the cool makeup air mixes with the outdoor unit's exhaust air to maintain the desired temperature setpoint. The booster fan recirculates the mixed air back to the inlet of the heat pump. Also, the booster fan speed, which is controlled by the laboratory, draws additional air through the outdoor unit to provide air mass flow rates equivalent to sea level conditions.

The test article makes compressor speed adjustments once per minute based on the temperature deviation between the space temperature and the thermostat's setpoint. As the space temperature deviates further from the setpoint temperature, the thermostat communicates with the indoor and outdoor units to increase the cooling capacity. The heat pump will speed up its compressor and

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fans based on its embedded controls. As the space temperature approaches the setpoint, the thermostat will decelerate the system speed. The laboratory indirectly modulates the heat pump speed by connecting a signal to the thermostat, which emulates a remote room temperature sensor. This signal becomes the primary space temperature input to which the thermostat reacts. The laboratory uses a feedback control loop that varies the emulated space temperature signal until the compressor speed matches the desired compressor setpoint value (Figure 13).

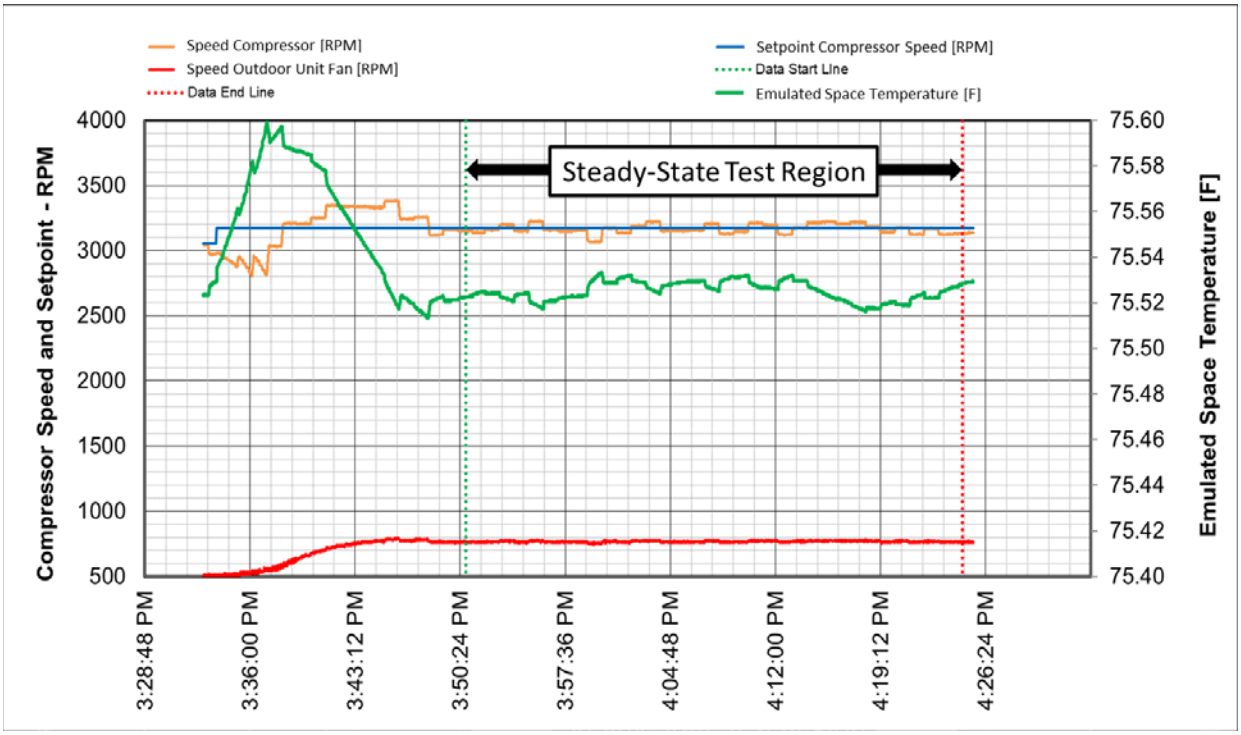

Figure 13. Controlling the compressor speed by emulating a room temperature signal on the thermostat

The thermostat monitors humidity as the secondary input for controlling the indoor unit fan. The humidistat is a small sensing chip built onto the control board of the thermostat. During experimentation, the thermostat was mounted in the return air plenum such that the thermostat could sense the humidity entering the air-handler (Figure 14).

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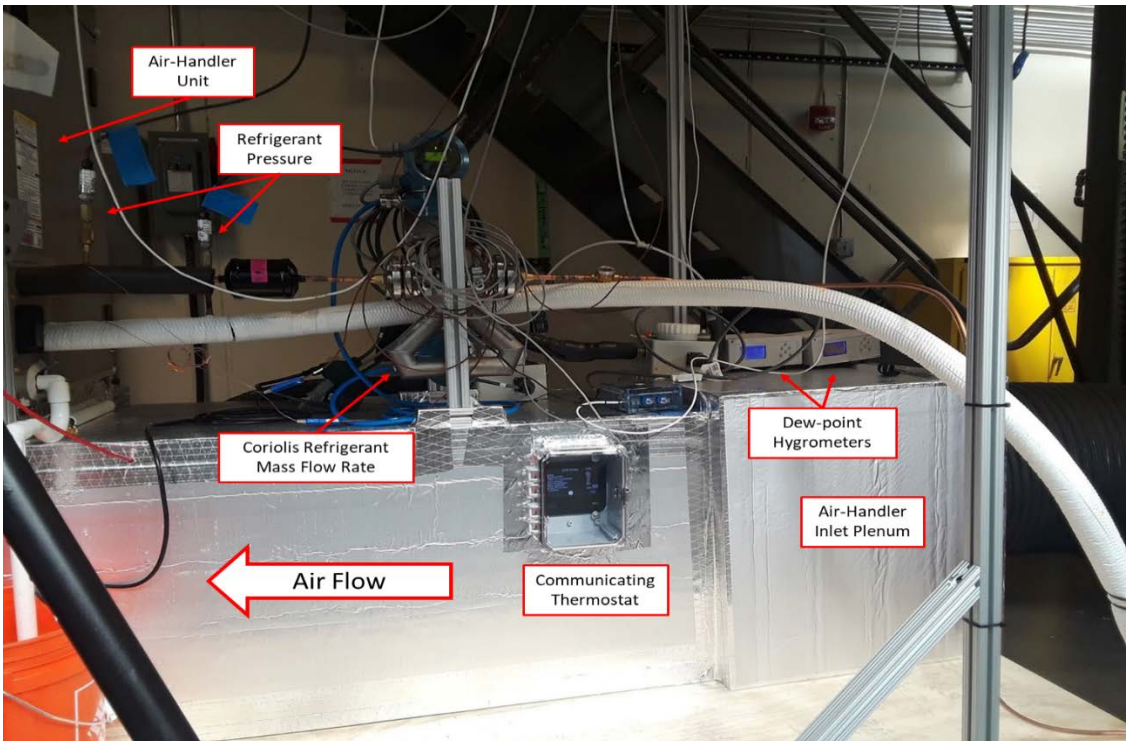

Figure 14. Thermostat and instrumentation on the indoor unit

During experimentation, steady-state conditions of the laboratory and the heat pump operation must be achieved before data collection. This is assessed by monitoring variables related to the air temperatures, dew-points, flow rates, and pressures as well as the heat pump compressor speed, fan speeds, and the refrigerant pressures. Once steady-state operation has been reached, more than 200 data variables are collected once per second over a 20- to 45-minute interval. The data is then postprocessed to adjust for altitude effects. The test matrix containing the adjusted, postprocessed values for steady-state cooling performance can be found in Table 17 and Table 18 in the Appendix.

3.4.2 Steady-State Heating Mode Tests

The methodology and laboratory operation to characterize the unit in heating mode is similar to the approach for cooling performance characterization. Constant psychrometric inlet conditions are supplied to the indoor unit and the environmental chamber to reach steady-state operation. The laboratory senses and adjusts dynamically using feedback controls to maintain temperature, humidity, air flow, and pressure setpoints to the indoor and outdoor units.

In heating mode, the outdoor unit removes heat from the air inside of the environmental chamber. This process continuously cools the chamber to lower temperatures. The laboratory fans exhaust a small portion of this cold air and supply warm makeup air back into the chamber to ensure the chamber air temperature remains constant during testing. To maintain the desired temperature setpoint, the environmental chamber dampers modulate proportionally, which mixes the warm makeup air with the cold air exhausted by the heat pump. The booster fan recirculates the mixed air back to the inlet of the heat pump. It also draws additional air through the outdoor unit to provide air mass flow rates equivalent to sea level conditions. However, it was observed

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that additional air mass flows at the colder temperatures had negligible effects on capacity and power, therefore at temperatures less than 18ºF, air flow through the outdoor coil was drawn solely by the outdoor unit fan. The laboratory indirectly modulates the heat pump compressor speed similar to cooling mode. This is done by sending a control signal to the thermostat, which emulates a space temperature. In heating mode, the humidity measurements taken by the thermostat do not affect the operation of the system.

During steady-state tests, achieving equilibrium between the lab's environmental conditions and the heat pump operation is critical prior to data collection and performance analysis. In addition, the characterization must be conducted between defrost cycles and preferably with minimum frost formation on the coil. If a defrost cycle begins during a test, the chamber temperature rises, and the test must be restarted until steady-state conditions are re-established. Once steady-state operation has been reached, data collection begins. The data is then postprocessed to adjust for altitude effects. The test matrix containing the adjusted, postprocessed values for steady-state heating performance can be found in Table 19 and Table 20 in the Appendix.

3.4.3 Integrated Defrost Degradation Tests

A limited number of experiments were performed due to the long nature of the test to collect a single set of psychometric conditions. These tests operate the heat pump over an 8- to 12-hour period where indoor and outdoor psychometric conditions are held constant. The objective is to allow for heavy frost accumulation to ascertain performance degradation.

During defrost tests, the air-handler unit inlet condition was maintained at 68ºF. This average return air temperature value was selected to minimize the number of independent variable test combinations. The outdoor unit was exposed to high humidity conditions inside the environmental chamber with a dew-point depression of only 2ºF below the dry-bulb temperature. The environmental chamber's dry-bulb temperature was varied from 7ºF to 40ºF, and the system was operated either at the minimum or maximum compressor speed.

The compressor speed during defrost is solely dependent on the outdoor air temperature and is independent of comfort or efficiency mode setting. The defrost compressor speeds were measured at 3,850, 4,450 and 5,350 RPMs (Figure 15). The heat pump terminates the defrost cycle under one of two conditions:

1. If the outdoor air temperature is warmer than 25ºF, defrost ends when the outdoor coil temperature sensor rises above 60ºF
2. If the outdoor air temperature is below 25ºF, defrost ends when the outdoor coil temperature sensor rises above 45ºF.

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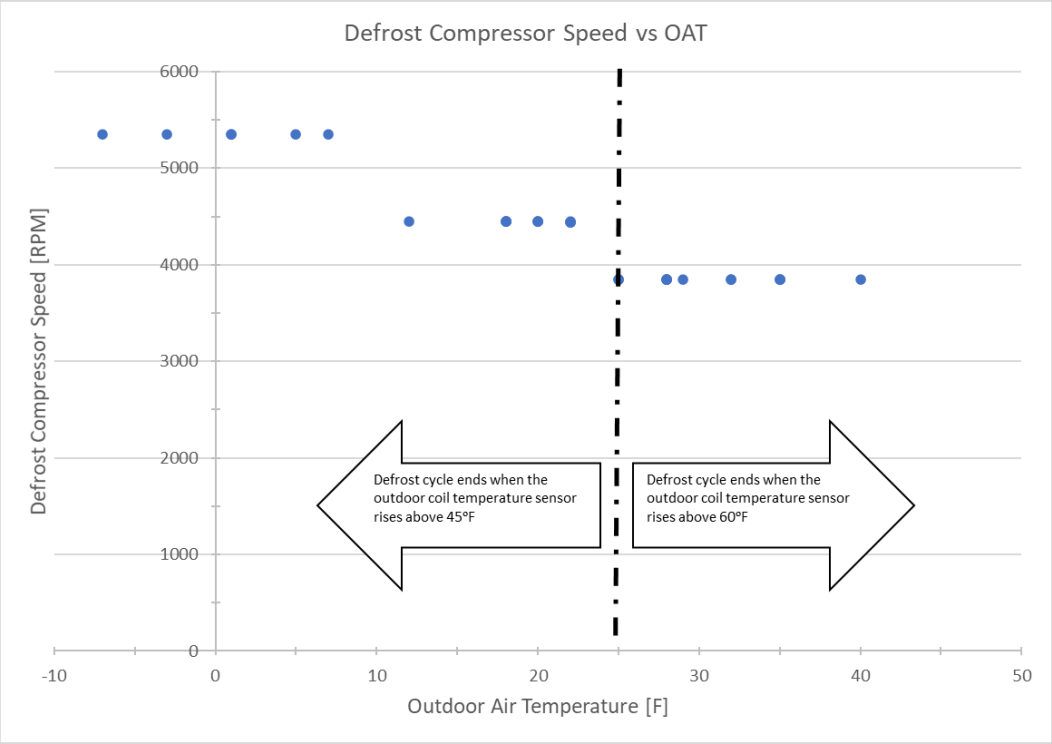

Figure 15. Compressor speed during the defrost cycle as a function of the outdoor air temperature

For all defrost tests, the environmental chamber booster fan was not used to boost the air mass flow though the outdoor unit coil. Because the booster fan only assisted in recirculating the air around the test chamber, the reduced volumetric air flow from frost accumulation could be measured. Also, during all defrost cycle tests, the thermostat was set to the default, "Auto," defrost time interval. When set to "Auto," the test article identifies a defrost need only when the outdoor air temperature is below 50ºF, and the outdoor unit coil (surface) temperature is below 32ºF. If these conditions are met, a timer limits the heating cycle run time to 30, 60, 90, or 120 minutes. The heating run time interval is based on the amount of time the prior defrost cycle ran. The less time required to defrost the outdoor coil, the more time the heat pump will spend running the following heating cycle. The corollary is also true such that if longer time is needed to defrost the outdoor coil, the heat pump will operate the subsequent heating cycle for less time.

The 8-hour time series shown in Figure 16 contains seven defrost cycles and six heating cycles. Trend lines of the heating capacity degradation, reduced air flow, the electrical power, and gross COP show the system performance as frost accumulates and how the amount of time spent in defrost dictates the following heating cycle time interval. The first defrost interval lasts 4 minutes, while the following heating cycle operates for 90 minutes. During the longer heating cycle, abundant ice accumulation gradually degrades the heating capacity until another defrost cycle is triggered. A longer defrost interval of 7 minutes is required to thaw the ice. Due to the longer defrost time interval, the test article limits the subsequent heating cycle to run for 30 minutes. The manufacturer's automatic defrost control logic is explained in further detail by referencing the service manual or Figure 27 in the Appendix.

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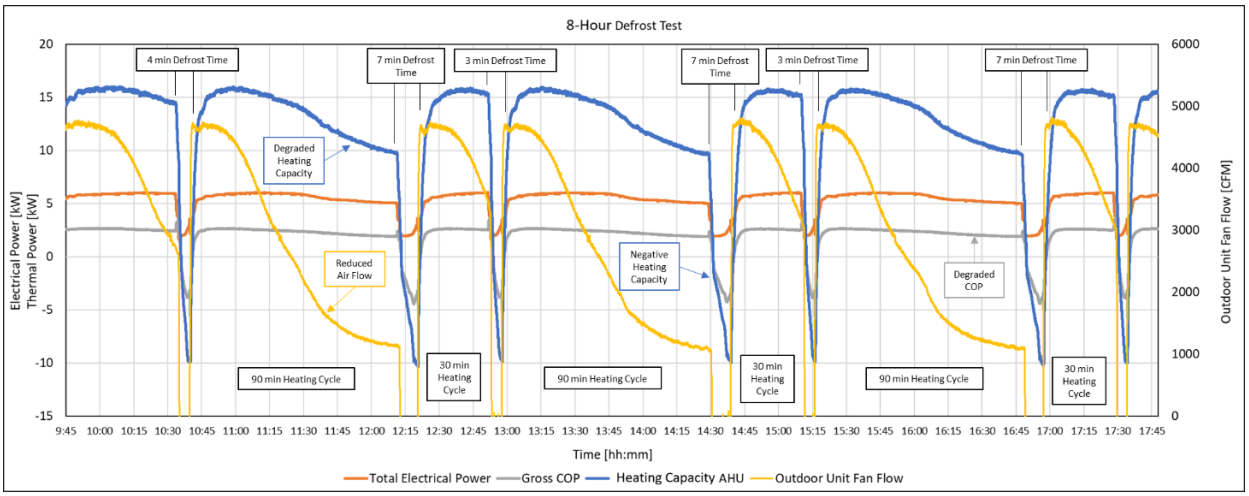

Figure 16. Defrost and performance degradation cycles over an 8-hour period maintaining an outdoor air temperature of 28°F

3.5 Regressing the Performance Data

The postprocessed data from Table 17 through Table 20 in the Appendix were used to compile performance prediction regressions. Each data table, representing comfort and efficiency mode, was treated separately. Furthermore, the dry-coil and wet-coil conditions in cooling mode were regressed independently. This resulted in a total of four sets of regressions that characterize cooling performance and two sets of regressions for heating performance. The varied test parameters and the postprocessed performance data were input into the statistical software package, JMP®. The software creates a second order, response surface methodology (RSM) model to empirically fit the postprocessed performance data relative to the independent variables. If any factors or cross terms in the regression were identified as statistically insignificant, they would be removed from the predictive model.

The RSM regressions are then used to develop an extensive lookup table that interpolates the heat pump capacity and performance to any permutation of parameters within the range of the test variables. The interpolated performance is used to provide EnergyPlus empirical predictions needed to simulate the heat pump annual energy consumption.

3.5.1 Steady-State Cooling Performance Regressions

The independent variables and the postprocessed tests were used to regress cooling performance parameters found in Table 9. The regressions are developed sequentially working from the top of the table down. The indoor, return air, wet-bulb temperature was used in these regressions as an independent variable derived from the indoor return air dry-bulb temperature and dew-point depression.

Using the empirical performance regressions, a lookup table was created for input into the EnergyPlus simulation environment. This table provides the predicted heat pump cooling performance parameters based on the compressor speed, outdoor dry-bulb air temperature, indoor dry-bulb return air temperature, and indoor return air wet-bulb temperature. When generating the lookup table, if the SHR was predicted to be a value of 1 or more, all dry-coil

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performance regressions were substituted for the originally assumed wet-coil cooling performance.

Table 9. Independent Variables, Measured and Calculated Performance Values Used in the RSM Cooling Predictive Models

RSM Performance Regressions	Factors Used in Regressions
Indoor standard volumetric flow rate	Compressor speed; Outdoor dry-bulb air temperature; Indoor return air wet-bulb temperature
Indoor external static pressure	Indoor standard volumetric flow rate
Air-handler, fan power	Indoor standard volumetric flow rate; Indoor external static pressure
Gross cooling capacity	Compressor speed; Outdoor dry-bulb air temperature; Indoor return air wet-bulb temperature
Gross sensible heat ratio	Compressor speed; Outdoor dry-bulb air temperature; Indoor return air dry-bulb temperature; Indoor return air wet-bulb temperature; Indoor standard volumetric flow rate
Gross COP	Compressor speed; Outdoor dry-bulb air temperature; Indoor return air wet-bulb temperature

A comparison between the RSM cooling predictive regressions and the experimental data can be found in the Appendix. The performance regressions represent the mean predicted value with error bars that show the 2 sigma (U95) confidence interval. Figure 23 and Figure 24 show the quality of the fit relative to the data in comfort mode and efficiency mode, respectively. Predictions for the heat pump performance during simulation are kept within the ranges specified in Table 7 to eliminate unknown uncertainty and inaccuracy outside of the fit.

3.5.2 Steady-State Heating Performance Regressions

The independent variables and the postprocessed tests were used to regress heating performance parameters found in Table 10. The regressions are developed sequentially working from the top of the table down. The heating capacity was determined by assessing the sensible heating across the indoor coil after steady-state operations was reached and while the outdoor unit was performing under no or low frost conditions.

Using the empirical performance regressions, a lookup table was created for input into the EnergyPlus simulation environment. This table provides the predicted heat pump heating performance based on the compressor speed, outdoor dry-bulb air temperature, and indoor dry-bulb return air temperature.

A comparison between the RSM heating predictive regressions and the experimental data can be found in the Appendix. The performance regressions represent the mean predicted value with error bars that show the 2 sigma (U95) confidence interval. Figure 25 and Figure 26 show the quality of the fit relative to the data in comfort mode and efficiency mode, respectively. While the best practice is to test and regress the heat pump performance over the full range of simulated conditions, the tests were limited to a low outdoor air temperature of -7ºF. Extrapolation of the performance regressions to an outdoor air temperature of -15ºF were used in simulation because this is the manufacturer's specified limit of the equipment's operation.

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Table 10. Independent Variables, Measured and Calculated Performance Values Used in the RSM Heating Predictive Models

RSM Performance Regressions	Factors Used in Regressions
Indoor standard volumetric flow rate	Compressor speed; Outdoor dry-bulb air temperature
Indoor external static pressure	Indoor standard volumetric flow rate
Air-handler, fan power	Indoor standard volumetric flow rate; Indoor external static pressure
Gross heating capacity	Compressor speed; Outdoor dry-bulb air temperature; Indoor return air dry-bulb temperature
Gross COP	Compressor speed; Outdoor dry-bulb air temperature; Indoor return air dry-bulb temperature
Supply air temperature from the air-handler unit	Compressor speed; Outdoor dry-bulb air temperature; Indoor return air dry-bulb temperature

Using the predictive performance regressions, the heating capacity and COP over a wide range of outdoor air conditions can be seen in Figure 17. The region represents the heating performance over the full range of compressor speeds at indoor return air temperatures between 68ºF and 76ºF. As the compressor speed decreases, the heating capacity decreases and the heat pump COP increases. As the indoor return air temperature increases, more compressor lift is required, so both the heating capacity and COP decrease.

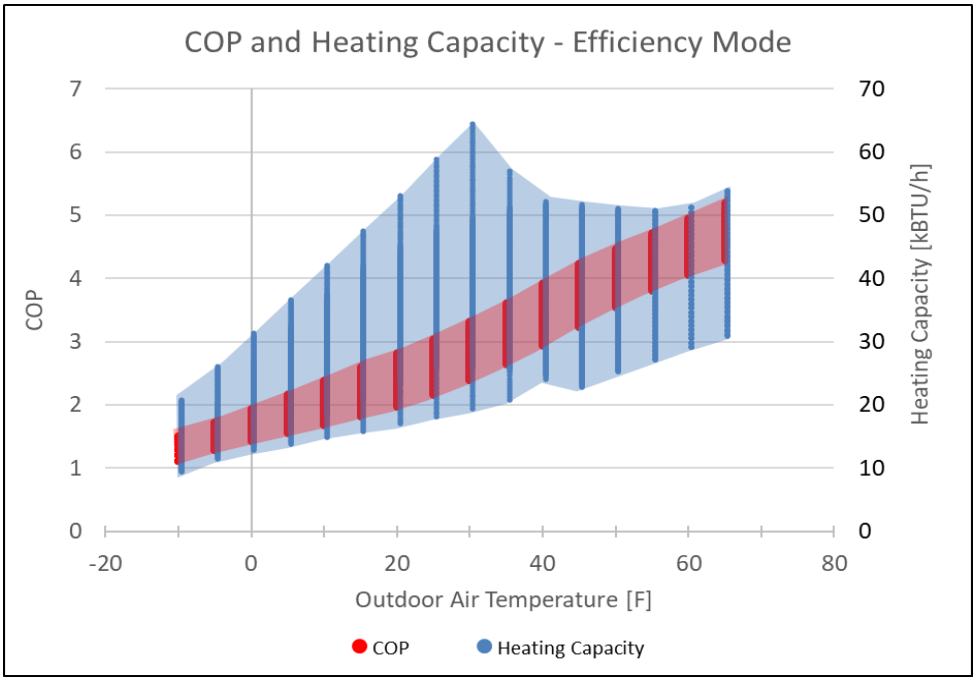

Figure 17. Expected range of varying heating capacity and COP versus outdoor air temperatures

3.5.3 Integrated Defrost Degradation Factor Regressions

Eleven tests were performed under high-humidity conditions to allow for multiple defrost cycles to occur during each test. Over the test period, the time varying heat capacity and COP was

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analyzed and averaged. All values were adjusted for sea level corrections. The average performance over that period was compared with the predicted steady-state performance of the heat pump operating under low frost conditions. A ratio of the average, high-humidity performance to the maximum steady-state performance in a low-humidity environment provides a derating factor that allows an estimate of the system operation including defrost events. The derating factors are a fractional value between zero and one.

Multiplying the respective derating fractions to the idealized, low frost, steady-state performance provides an effective heating capacity and COP. The effective values capture the energy usage during the heating cycle, the defrost cycle plus the cooling effect (negative capacity) from the space that provides the heat to thaw the outdoor coil. The defrost tests attempt to characterize the heat pump operation under very humid conditions, while the low frost, steady-state data provides the systems maximum performance. The two tests will bracket the annual performance of the equipment. It should be noted that the heat pump could experience even more extreme weather conditions that cannot be easily characterized in the laboratory nor with an EnergyPlus simulation. When the heat pump operates in snow or near freezing rain, the rates of ice accumulation, performance degradation, and defrost cycle frequency are expected to increase dramatically.

The data revealed that a piecewise regression is needed, because a cusp at 25ºF was observed (Figure 18). This discontinuity is due to the heat pump control logic, which ends the defrost cycle at different outdoor coil temperatures above and below an outdoor air temperature of 25ºF. The system has the largest capacity degradation at conditions near freezing where the air contains more moisture and is nearest the frost point. There are two distinct curves for the minimum and maximum heat pump speed. However, at outdoor conditions below 25ºF, the capacity derating appears to be independent of the compressor speed. The system initiates shorter duration defrost cycles between typically 90- and 120-minute heating cycle intervals. Because the colder air contains less water vapor, frost accumulation occurs at slower rates despite the highest heat pump speeds and the coldest coil temperatures. Upon developing this regression, more tests points would help to better understand the trends at low temperatures. A few estimates were included to better approximate a regression below 25ºF.

During the eleven tests performed, a total of 56 defrost cycles occurred. The COP derating was plotted using higher-fidelity averages on a cycle-by-cycle basis, as shown in Figure 19. The correlation of the COP degradation is directly proportional to the capacity degradation. This is expected because the COP is a ratio of the capacity to the heat pump input energy.

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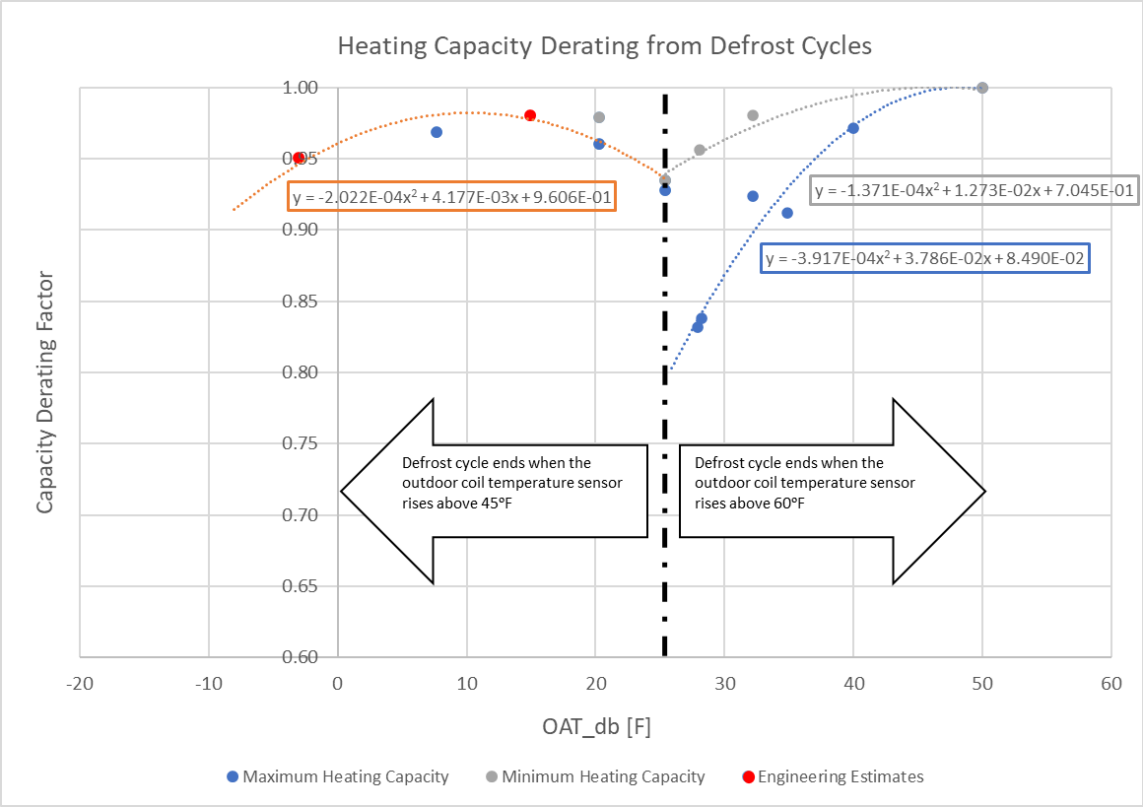

Figure 18. Estimated capacity derating factors regressions to account for defrost cycles

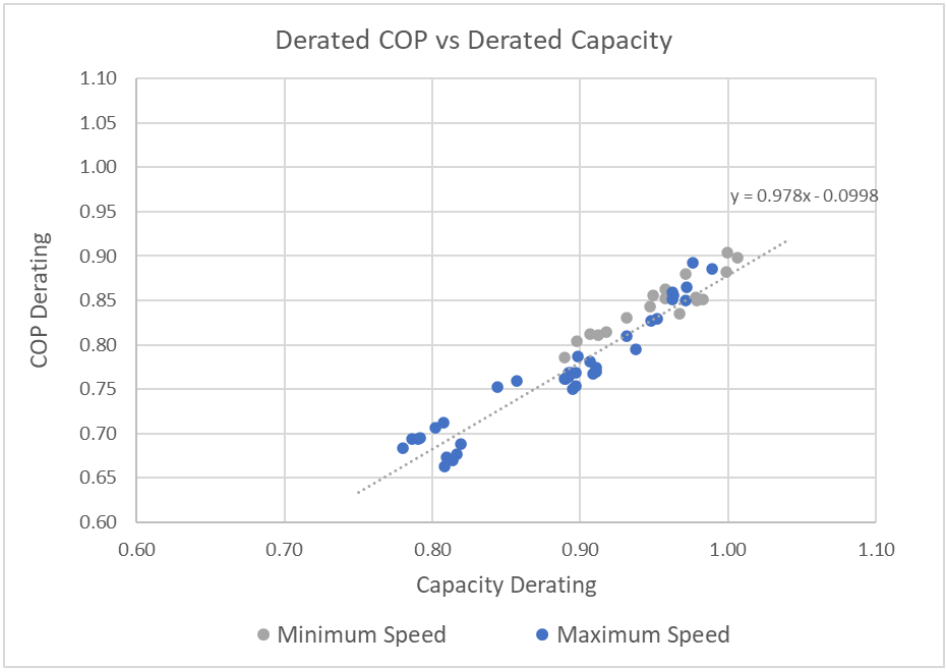

Figure 19. COP derating as a function of the capacity derating factor

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4 Energy Modeling Setup

EnergyPlus 9.5 is the software used for the simulation of the advanced heat pump model. EnergyPlus is a free, open-source, cross-platform, whole-building hourly energy simulation program that engineers, architects, and researchers use to model both energy consumption—for heating, cooling, ventilation, lighting and plug and process loads—and water use in buildings. The console-based program reads input and writes output to text files.

The heat pump's performance is simulated for three DOE prototype buildings: a single-family home, a strip mall, and a low-rise office building. These prototype building models are available on the DOE database of typical building models (referenced below). The buildings follow IECC 2021 recommendations for ASHRAE climate zone 5A. A brief description of the features of these buildings is given in Table 11. The HVAC operation, occupancy, equipment, lighting, and ventilation schedules are also defined by default in these buildings and are obtained from the ASHRAE users' manual 2014. The buildings are simulated for the city of Chicago, using the TMY3 weather file for the Chicago O'Hare international airport.

Table 11. Summary of Different DOE Prototype Buildings Simulated

Parameters	Single-Family Home	Strip Mall	Low-Rise Office
Total building area (sf)	3,565	22,500	5,502
Window-wall ratio (%)	14%	11%	21%
Hours of operation	24/7	Store type 1: 9:00-24:00 Store type 2: 9:00-21:00 Store type 3: 9:00-19:00	Weekdays: 8:00-17:00
Baseline HVAC system description	Single-stage heat pump with direct expansion (DX) cooling, reverse DX electric heating, and supplemental electric heat	Single-stage heat pump RTU with DX cooling, reverse DX electric heating, and supplemental electric heat	Single-stage heat pump RTU with DX cooling, reverse DX electric heating, and supplemental electric heat
Heating efficiency	7.9 HSPF	7.5 HSPF	7.5 HSPF
Cooling efficiency	13.0 SEER	12.0 SEER	12.0 SEER
Supply fan efficiency	0.4 W/cfm	0.5 W/cfm	0.5 W/cfm

For simulating the ComEd advanced heat pump, the experimental data described in the previous sections **for efficiency mode** were translated into an EnergyPlus readable format. This was done through the following process.

- The experimental data were translated from their raw form into `Table:Lookup` objects. These objects map the independent variables (the outdoor air dry-bulb temperature and the entering wet-bulb temperature of the coil in this case) to the capacity of the heat pump. The lookup table object is specified to use either linear or cubic interpolation independently for each input variable. For performance points outside the defined grid

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space, an extrapolation method—constant or linear—is set independently for each dimension. The table also has two specified values above and below which extrapolation is not permitted.

- The `Table:Lookup` objects are referenced by the cooling capacity as a function of temperature (*CoolCapfT*) and heating capacity as a function of temperature (*HeatCapfT*) curves. For each set of these curves, a reference-rated cooling/heating capacity, COP, and a reference-rated air flow rate are specified. There are 10 such curves specified for each heating and cooling coil, and each of these curves use a `Table:Lookup` object. Each curve is representative of a particular speed of operation of the heat pump.

- The same procedure is repeated to reference `Table:Lookup` objects to Energy Input Ratio as a function of temperature curves (*EIRfT*). The Energy Input Ratio is the inverse of COP. The independent variables for the table objects are once again the entering wet-bulb temperature and the outdoor air dry-bulb temperature. 10 such curves are specified for the heating and cooling coils.

- The curves described above are referenced by `Coil:Cooling:DX:VariableSpeed` and `Coil:Heating:DX:VariableSpeed` objects. These objects in EnergyPlus simulate different speed-rated performance of the cooling and heating coils specified. In this simulation, 10 different speeds are specified.

- The two coils are wrapped in a `AirLoopHVAC:UnitaryHeatPump:AirToAir` object to complete the setup of the advanced heat pump model. These two coils are complemented by a supplemental backup electric heating coil.

For all the DOE prototype buildings referenced above, simulations were run for both a baseline case and an advanced case. The results and savings of these simulations are discussed next.

5 Energy Modeling Results

This section discusses the energy modeling results for the baseline models described in Section 4 retrofitted with a high-efficiency heat pump.

Figure 20 shows the whole-building energy savings for a single-family home retrofitted with the high-efficiency heat pump model as compared to a baseline model with a standard efficiency heat pump unit.

The single-family home prototype shows relatively lower savings (22.1%) than the other two building models represented here (29.3% for strip mall, 28% for office). This is due to the following reasons:

- The single-family home model has relatively low supply fan savings (13.1%). This is because in the baseline model for this building type, the supply fans cycle only when heating and cooling is required, and they are turned off otherwise. In the other two commercial buildings, the fans are required by the building's Uniform Mechanical Code to be operational during business hours to meet ventilation and indoor air quality requirements in compliance with the Uniform Mechanical Code.

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- The magnitude of internal loads, which need to be met by the HVAC system, are also smaller in a residential building model as compared to the other two commercial building prototypes.

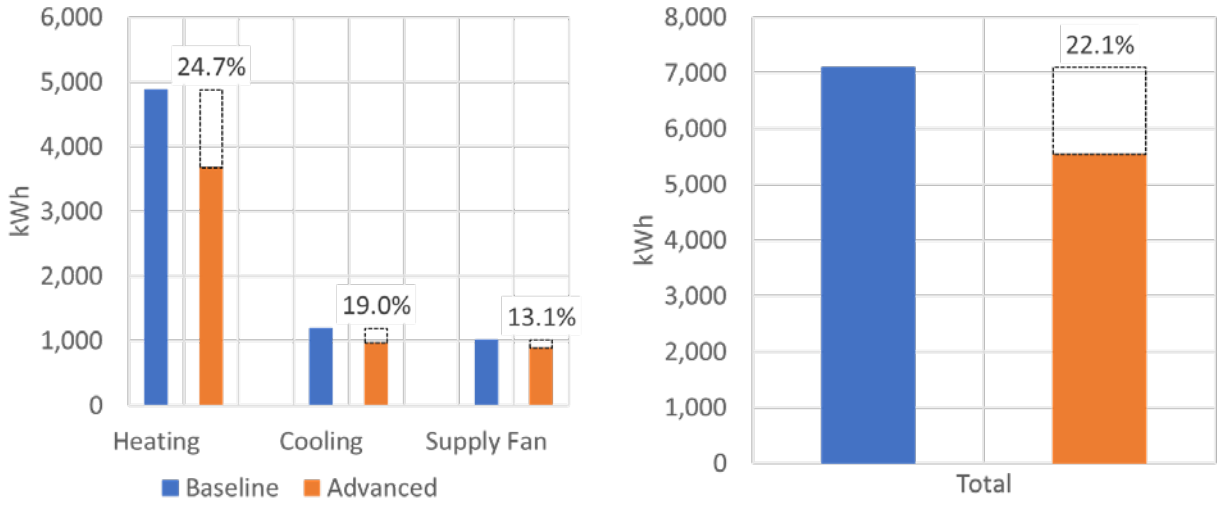

Figure 20. HVAC energy use comparison for a single-family home with the high-efficiency heat pump model. The figure on the left shows the end-use savings breakdown, and the figure on the right shows the total site energy use for the baseline and high-efficiency heat pump models.

Figure 21 shows the savings for the strip mall building prototype with a high-efficiency heat pump.

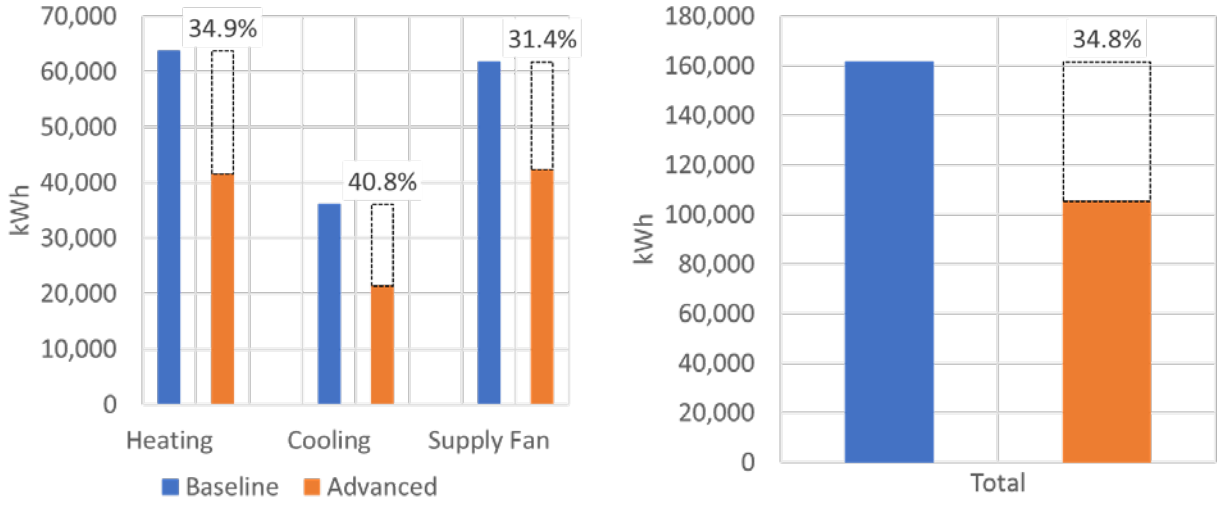

Figure 21. HVAC energy use comparison for a strip mall with the high-efficiency heat pump model. The figure on the left shows the end-use energy consumption breakdown, and the figure on the right shows the total site energy use for the baseline and high-efficiency heat pump models.

The strip mall prototype model shows the highest energy savings over its respective baseline, both in terms of percentage and in terms of absolute energy savings numbers. There are a couple of reasons for this:

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- The increased absolute energy savings are likely due to the large square footage of the strip mall (see Section 4). More conditioned area means more loads to be met, and therefore higher energy usage (and subsequently higher absolute savings) for the building.

- A strip mall also has significantly higher ventilation requirements to accommodate considerably more occupied hours and loads that need to be satisfied by the HVAC system. This translates to increased time of operation and capacity of the baseline system as well as the advanced heat pump model.

- The load for the strip mall occurs coincidentally with lower ambient temperatures (due to longer operating hours). This would utilize the baseline's strip heating coil more, leading to higher baseline energy usage. The performance of the advanced heat pump, however, would help minimize the utilization of the strip heater in the unit, and therefore realize more savings.

- The more the systems run, the more the opportunity for the advanced heat pump system to perform better and thereby reduce consumption of energy. These factors translate to more savings.

Figure 22 shows the savings for the low-rise office building prototype with a high-efficiency heat pump.

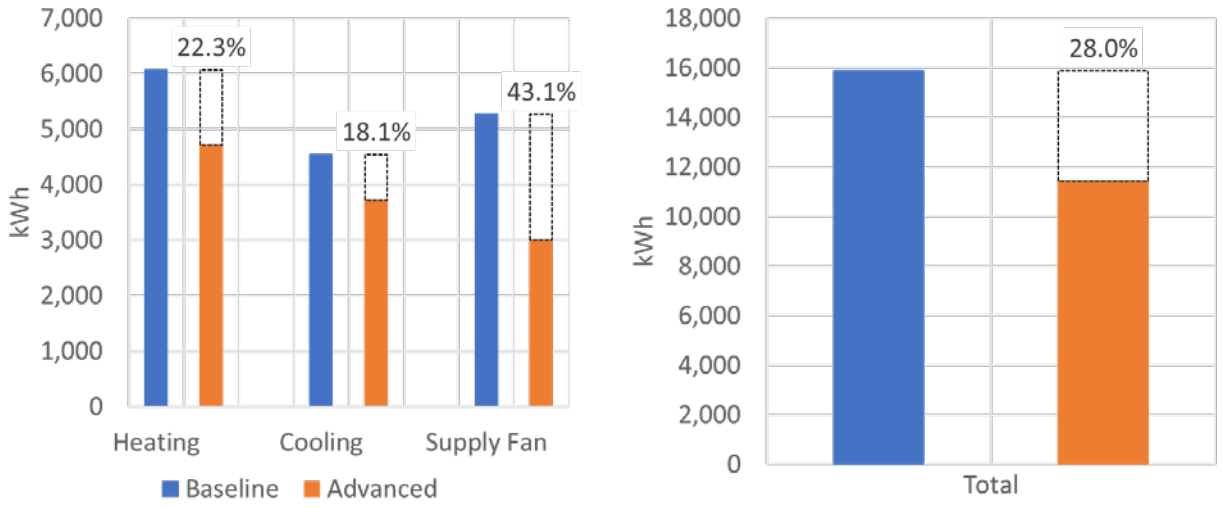

Figure 22. HVAC energy use comparison for low-rise office building with the high-efficiency heat pump model. The figure on the left shows the annual end-use energy consumption breakdown, and the figure on the right shows the total site annual energy use for baseline and the high-efficiency heat pump model.

The low-rise office building's energy savings are comparable to the strip mall prototype. The lower ventilation requirements of the low-rise office buildings and reduced hours of operation are probably why the overall savings are slightly lower than the strip mall prototype.

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6 Conclusion

Table 12 shows a summary of the energy savings for the three different prototypes simulations.

Table 12. Energy Savings Summary for the Different DOE Prototype Buildings Simulated

Parameters	Single-Family Home	Strip Mall	Low-Rise Office
Heating energy savings	24.7%	34.9%	22.3%
Cooling energy savings	19.0%	40.8%	18.1%
Supply fan energy savings	13.1%	31.4%	43.1%
Total (heating, cooling, and supply fan) energy savings	22.1%	34.8%	28.0%

The higher COP of the high-efficiency heat pump under Chicago's low winter temperatures resulted in significant heating energy savings in all three buildings The higher compressor COP also contributed to moderate annual cooling energy savings. The high-efficiency supply fan motor and variable-speed controls of the high-efficiency heat pump provided additional fan energy savings for all three building models.

The strip mall building shows the highest whole-building energy savings (29.3%) over its respective baseline. The low-rise office building's savings are similar (28%), while the single-family home building has a slightly reduced energy savings due to reduced supply fan energy savings. Overall, all buildings show significant energy savings over their respective baseline and make a strong case for the utilization of these heat pumps.

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Appendix A. Instrumentation Plan

Table 13. Critical Experimental Measurements and Sensors

System	Physical Location	Instrument Type
Outdoor unit	Dry-bulb average inlet louver side 1	4 TC probes
Outdoor unit	Dry-bulb average inlet louver side 2	4 TC probes
Outdoor unit	Dry-bulb average inlet louver side 3	4 TC probes
Outdoor unit	Dry-bulb average inlet louver side 4	4 TC probes
Outdoor unit	Dry-bulb average outlet	9 TC probes
Outdoor unit	Dew-point inlet	Dew-point hygrometer
Outdoor unit	Dew-point outlet	Dew-point hygrometer
Outdoor unit	Total power	Power meter
Outdoor unit	Compressor power	Power meter
Outdoor unit	Fan power	Power meter
Outdoor unit	Air flow	Avg pitot tube array
Outdoor unit	Outdoor unit fan speed	Optical tachometer
Outdoor unit	Compressor speed	Frequency/pulse meter
Outdoor unit	Outdoor unit coil temperature	Surface TC
Outdoor unit	Compressor inlet temperature	Surface TC
Outdoor unit	Compressor outlet temperature	Surface TC
Air-handler unit	Dry-bulb average inlet	9 TC probes
Air-handler unit	Dry-bulb average outlet	9 TC probes
Air-handler unit	Dew-point inlet	Dew-point hygrometer
Air-handler unit	Dew-point outlet	Dew-point hygrometer
Air-handler unit	Indoor unit fan speed	Optical tachometer
Air-handler unit	Inlet AHU[1] mass flow rate	Laboratory nozzles
Air-handler unit	Outlet AHU mass flow rate	Laboratory nozzles
Air-handler unit	Differential pressure—inlet/outlet	Differential pressure transducer
Air-handler unit	Differential pressure—inlet/ambient	Differential pressure transducer
Air-handler unit	Total power	Power meter
Refrigerant line	Suction line temperature near OU	Surface TC
Refrigerant line	Suction line temperature near AHU	Surface TC
Refrigerant line	Liquid line temperature near OU	Surface TC
Refrigerant line	Liquid line temperature near AHU	Surface TC
Refrigerant line	Suction line pressure near OU	Gauge pressure transducer
Refrigerant line	Suction line pressure near AHU	Gauge pressure transducer

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System	Physical Location	Instrument Type
Refrigerant line	Liquid line pressure near OU	Gauge pressure transducer
Refrigerant line	Liquid line pressure near AHU	Gauge pressure transducer
Refrigerant line	Refrigerant mass flow rate	Coriolis mass flow meter
Refrigerant line	Refrigerant density	Coriolis mass flow meter
Lab	Dry-bulb ambient	TC probes
Lab	Dew-point ambient	Hygrometer
Lab	Ambient barometric pressure	Barometric pressure transducer
Environmental chamber	Booster/recirculation fan speed	Variable frequency drive
Environmental chamber	Differential pressure—inlet/outlet plenum	Differential pressure transducer
Environmental chamber	Differential pressure—inlet plenum/ambient	Differential pressure transducer
Environmental chamber	Damper—makeup air	Rotary actuator
Environmental chamber	Damper—bypass air	Rotary actuator

[1] AHU = air-handler unit

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Appendix B. Test Matrix

Table 14. Cooling (Wet-Coil) Steady-State Test Conditions (Comfort Mode and Efficiency Mode)

Test Number	JMP OAT [°F]	JMP RA_db [°F]	JMP dp_Depression [°F]	Dew-point [°F]	JMP Compressor Speed [RPM]
Test1	92.9	75.7	25	50.7	1,850
Test2	120	82	25	57	3,410
Test3	55	82	18.25	63.75	4,250
Test4	92.6	68	25	43	1,850
Test5	55	68	25	43	4,250
Test6	81	82	17.5	64.5	4,250
Test7	107	68	10	58	2,661
Test8	120	68	17.5	50.5	3,391
Test9	120	82	10	72	4,250
Test10	90.75	68	10	58	4,250
Test11	81	75	18.25	56.75	3,290
Test12	55	75	10	65	4,250
Test13	61.5	82	25	57	1,970
Test14	103.75	82	17.5	64.5	2,442
Test15	113.5	75.7	10	65.7	3,050
Test16	74.5	82	10	72	3,290
Test17	55	68	10	58	2,930
Test18	55	76.4	25	51.4	2,810
Test19	113.5	75	18.25	56.75	3,050
Test20	94	73.6	17.5	56.1	4,250
Test21	94	73.6	10	63.6	1,970
Test22	64.75	82	10	72	1,886
Test23	92.7	82	17.5	64.5	1,850
Test24	81	68	25	43	3,170
Test25	87.5	82	25	57	4,250
Test27	61.5	68	16.75	51.25	1,921
Test28	61.5	73.6	16.75	56.85	1,970
Test29	120	70.8	25	45.8	4,250
Test30	95	82	22.75	59.25	1,970

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Table 15. Cooling (Dry-Coil) Steady-State Test Conditions (Comfort Mode and Efficiency Mode)

Test Number	JMP OAT [°F]	JMP RA_db [°F]	JMP dp_Depression [°F]	Dew-point [°F]	JMP Compressor Speed [RPM]
Test1	120	75	50	25	4,250
Test2	94	82	50	32	4,250
Test3	90.75	68	50	18	4,250
Test4	55	82	50	32	4,250
Test5	55	68	50	18	4,250
Test6	120	68	50	18	3,410
Test7	81	74.3	50	24.3	3,290
Test8	77.75	74.3	50	24.3	3,290
Test9	116.75	82	50	32	3,170
Test10	81	82	50	32	3,170
Test11	55	75	50	25	3,050
Test12	100.5	68	50	18	2,330
Test13	94	76.4	50	26.4	1,970
Test14	61.5	68	50	18	1,970
Test15	61.5	82	50	32	1,970

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Table 16. Heating Steady-State Test Conditions (Comfort Mode and Efficiency Mode)

Test Number	JMP OAT [°F]	JMP RA_db [°F]	JMP Compressor Speed [RPM]
Test1	60	73.6	3,395
Test2	60	65.6	3,395
Test3	49.5	60	1,850
Test4 [1]	42.5	60	4,425
Test5 [1]	39	65.6	4,940
Test6	37.6	76	2,365
Test7 [1]	35.9	76	5,198
Test8	28.5	68	2,880
Test9	21.5	60	4,168
Test10 [1]	20.2	76	7,000
Test11 [1]	19.8	68	7,000
Test12	18	60	7,000
Test13	18	67.2	3,138
Test14	5	67.2	3,050
Test15	5	76	3,050
Test16	0.5	68.8	5,713
Test17 [1]	-0.1	68	5,970
Test18 [1]	-0.5	76	5,455
Test19 [1]	-3	60	5,455
Test20 [1]	-7	61.6	4,900
Test21[1,2]	47	70	4,165

1 Test was run at the maximum compressor speed limited by the mode of operation.
2 AHRI 210/240 heating rating condition, tested in efficiency mode with a 43°F outdoor wet-bulb temperature.

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Appendix C. Steady-State Cooling Performance

Table 17. Test Conditions and Heat Pump Cooling Performance Adjusted for Sea Level Operation in Efficiency Mode

Test Conditions and Performance Data (Efficiency Mode) Adjusted for Sea Level Operation										
Test Conditions				Analyzed Performance						
Indoor Unit Coil Conditions		Outdoor Unit Coil Conditions	Compressor Speed (RPM)	Dry or Wet Coil Condition	Supply Fan Flow Rate (SCFM)	External Static Pressure (in w.c)	Supply Fan Power Draw (W)	Gross Total Cooling Capacity (kBtu/h)	Gross Sensible Heat Ratio	Gross COP
Entering Dry-Bulb Temperature (°F)	Entering Wet-Bulb Temperature (°F)	Entering Dry-Bulb Temperature (°F)								
82.0	67.1	95.0	1983	Wet	936	-0.180	138	30.11	0.840	4.518
68.0	54.3	55.0	4247	Wet	1,392	-0.440	410	52.27	0.850	4.918
75.0	68.2	55.0	4247	Wet	1,376	-0.470	438	68.73	0.500	5.958
82.0	69.5	55.0	4247	Wet	1,374	-0.470	437	70.09	0.610	6.052
76.4	61.2	55.0	2851	Wet	1,154	-0.320	250	43.90	0.830	6.871
68.0	61.6	55.0	2953	Wet	1,156	-0.320	254	45.78	0.570	6.839
68.0	58.1	61.5	1900	Wet	997	-0.240	170	27.86	0.800	6.340
73.6	63.0	61.5	1992	Wet	1,051	-0.270	201	32.67	0.750	6.921
82.0	65.9	61.5	1979	Wet	1,042	-0.270	198	34.56	0.880	7.384
82.0	74.8	64.8	1871	Wet	941	-0.230	162	38.96	0.480	8.875
68.0	54.3	81.0	3149	Wet	1,427	-0.480	442	39.06	0.960	3.879
75.1	63.6	81.0	3270	Wet	1,367	-0.460	421	47.92	0.730	4.565
82.0	70.0	81.0	4247	Wet	1,319	-0.440	390	65.01	0.600	4.729
82.0	65.9	87.5	4247	Wet	1,323	-0.430	380	58.04	0.760	4.029
82.0	74.8	74.5	3254	Wet	1,304	-0.440	399	60.88	0.470	6.099
68.0	54.3	92.6	1827	Dry	889	-0.190	123	20.10	1.000	3.456
75.7	60.6	92.9	1845	Wet	891	-0.190	128	24.05	0.960	4.033
82.0	70.1	92.7	1837	Wet	881	-0.200	133	30.21	0.700	5.052
68.0	61.7	90.7	4248	Wet	1,370	-0.460	421	52.65	0.580	3.519
73.6	62.6	94.0	4248	Wet	1,356	-0.460	411	52.63	0.700	3.403
70.8	56.6	120.0	4248	Wet	1,273	-0.390	330	39.30	0.920	2.005
82.0	74.8	120.0	4248	Wet	1,244	-0.420	356	58.02	0.470	2.883
73.6	66.9	94.0	1922	Wet	921	-0.220	146	29.48	0.570	4.604
82.0	65.9	120.0	3402	Wet	960	-0.220	159	38.96	0.790	2.603
68.0	57.7	120.0	3388	Wet	901	-0.190	129	31.04	0.750	2.118
75.0	63.4	113.5	3071	Wet	872	-0.180	122	35.07	0.700	2.840
68.0	61.7	107.0	2691	Wet	1,178	-0.350	277	33.28	0.620	3.096
82.0	70.0	103.8	2506	Wet	1,125	-0.330	256	37.41	0.710	3.871
75.7	69.0	113.5	3079	Wet	1,246	-0.410	342	41.48	0.550	3.067
75.0	50.4	120.0	4248	Dry	1,287	-0.390	325	40.11	1.000	2.054
82.0	53.4	94.0	4248	Dry	1,346	-0.430	372	50.10	1.000	3.298
68.0	47.2	90.7	4247	Dry	1,350	-0.410	359	42.87	1.000	2.975
68.0	46.1	120.0	3406	Dry	1,320	-0.420	351	31.29	0.990	1.970
82.0	52.8	116.7	3272	Dry	1,305	-0.420	354	38.81	1.000	2.618
68.0	50.3	100.5	2308	Dry	1,071	-0.280	197	25.05	1.000	3.040
76.4	54.1	94.0	1925	Dry	923	-0.210	137	23.99	1.000	3.776
68.0	49.6	61.5	1999	Dry	1,056	-0.270	188	27.50	1.000	5.922
82.0	54.8	61.5	1961	Dry	1,041	-0.270	188	32.67	1.000	7.062
68.0	45.8	55.0	4246	Dry	1,456	-0.480	443	49.80	1.000	4.664
82.0	52.2	55.0	4246	Dry	1,406	-0.460	416	57.93	1.000	5.309
75.0	49.5	55.0	3042	Dry	1,407	-0.470	422	44.38	1.000	5.837
82.0	52.5	81.0	3168	Dry	1,401	-0.470	427	45.57	1.000	4.471
74.3	48.8	81.0	3313	Dry	1,405	-0.470	419	42.60	1.000	4.049
74.3	49.8	77.8	3294	Dry	1,371	-0.440	390	42.52	1.000	4.259

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Table 18. Test Conditions and Heat Pump Cooling Performance Adjusted for Sea Level Operation in Comfort Mode

Test Conditions and Performance Data (Comfort Mode) Adjusted for Sea Level Operation										
Test Conditions				Analyzed Performance						
Indoor Unit Coil Conditions		Outdoor Unit Coil Conditions	Compressor Speed (RPM)	Dry or Wet Coil Condition	Supply Fan Flow Rate (SCFM)	External Static Pressure (in w.c)	Supply Fan Power Draw (W)	Gross Total Cooling Capacity (kBtu/h)	Gross Sensible Heat Ratio	Gross COP
Entering Dry-Bulb Temperature (°F)	Entering Wet-Bulb Temperature (°F)	Entering Dry-Bulb Temperature (°F)								
82.0	67.1	95.0	1979	Wet	644	-0.080	56	27.75	0.730	4.460
68.0	54.3	55.0	4247	Wet	1,400	-0.450	411	52.31	0.850	4.928
75.0	68.2	55.0	4248	Wet	1,377	-0.470	437	68.75	0.500	5.959
82.0	69.5	55.0	4248	Wet	1,376	-0.470	438	70.01	0.610	6.040
76.4	61.2	55.0	2819	Wet	1,151	-0.320	248	43.45	0.830	6.890
68.0	61.8	55.0	2941	Wet	1,039	-0.250	189	44.79	0.560	6.994
68.0	58.1	61.5	1930	Wet	729	-0.130	76	26.91	0.720	6.613
73.6	63.0	61.5	1972	Wet	738	-0.130	81	30.32	0.670	7.269
82.0	65.9	61.5	1950	Wet	740	-0.130	82	31.97	0.770	7.694
82.0	74.8	64.8	1897	Wet	707	-0.130	78	37.89	0.450	9.012
68.0	54.3	81.0	3166	Wet	1,310	-0.400	343	38.50	0.940	3.983
75.0	63.5	81.0	3300	Wet	1,160	-0.330	262	46.71	0.690	4.724
82.0	70.0	81.0	4247	Wet	1,319	-0.440	390	65.04	0.600	4.730
82.0	65.9	87.5	4247	Wet	1,324	-0.430	382	58.03	0.770	4.026
82.0	74.8	74.5	3309	Wet	1,161	-0.350	282	60.50	0.450	6.270
68.0	54.3	92.6	1836	Wet	779	-0.140	88	19.71	0.970	3.463
75.7	60.6	92.9	1840	Wet	756	-0.140	85	22.84	0.920	3.975
82.0	70.0	92.7	1845	Wet	654	-0.110	64	28.72	0.630	5.043
68.0	61.7	90.8	4248	Wet	1,370	-0.460	419	52.64	0.580	3.519
73.6	62.6	94.0	4248	Wet	1,357	-0.460	413	52.71	0.700	3.407
70.8	56.6	120.0	4248	Wet	1,364	-0.450	402	39.85	0.940	1.994
82.0	74.8	120.0	4248	Wet	1,285	-0.440	386	58.49	0.470	2.882
73.6	66.8	94.0	1923	Wet	629	-0.100	57	27.40	0.520	4.550
82.0	65.9	120.0	3411	Wet	985	-0.240	171	39.16	0.800	2.599
68.0	57.6	120.0	3402	Wet	903	-0.190	130	31.14	0.750	2.113
75.0	63.4	113.5	3070	Wet	871	-0.180	122	35.12	0.700	2.844
68.0	61.7	107.0	2684	Wet	806	-0.160	100	31.55	0.570	3.192
82.0	70.0	103.8	2504	Wet	766	-0.150	93	35.14	0.620	3.952
75.7	68.9	113.5	3074	Wet	866	-0.190	126	39.06	0.510	3.134
75.0	50.3	120.0	4248	Dry	1,345	-0.420	370	40.73	1.000	2.060
82.0	53.4	94.0	4248	Dry	1,347	-0.430	373	50.08	1.000	3.294
68.0	47.2	90.7	4247	Dry	1,354	-0.420	362	42.91	1.000	2.975
68.0	47.3	120.0	3440	Dry	1,183	-0.330	257	30.24	1.000	1.949
82.0	53.6	116.8	3269	Dry	1,156	-0.330	250	37.18	1.000	2.603
67.9	49.6	100.5	2305	Dry	917	-0.200	130	23.46	1.000	2.968
76.4	53.5	94.0	1941	Dry	812	-0.160	98	22.89	1.000	3.702
68.0	48.4	61.5	1967	Dry	929	-0.200	133	26.05	1.000	5.977
81.9	54.2	61.5	1940	Dry	916	-0.200	133	30.94	1.000	7.120
68.0	45.7	55.0	4246	Dry	1,456	-0.480	443	49.84	1.000	4.670
82.0	52.3	55.0	4246	Dry	1,406	-0.460	417	57.90	1.000	5.309
75.0	49.5	55.0	3054	Dry	1,336	-0.420	360	43.78	1.000	5.944
82.0	52.4	81.0	3160	Dry	1,320	-0.420	358	44.58	1.000	4.524
74.3	48.9	81.0	3305	Dry	1,367	-0.440	386	42.15	1.000	4.078
74.3	49.3	77.8	3279	Dry	1,366	-0.440	385	42.31	1.000	4.264

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Appendix D. Steady-State Heating Performance

Table 19. Test Conditions and Heat Pump Heating Performance Adjusted for Sea Level Operation in Efficiency Mode

Test Conditions and Performance Data (Efficiency Mode) Adjusted for Sea Level Operation								
Test Conditions			Experimental Test Result Adjusted for Sea Level Performance					
Indoor Unit Coil Conditions	Outdoor Unit Coil Conditions	Compressor Speed (RPM)	Supply Fan Flow Rate (SCFM)	External Static Pressure (in w.c)	Supply Fan Power Draw (W)	Gross Total Heating Capacity (kBtu/h)	T_db, Indoor_Supply (F)	Gross COP
Entering Dry-Bulb Temperature (°F)	Entering Dry-Bulb Temperature (°F)							
73.6	60.0	3472	1,388	-0.570	543	50.97	108.300	4.113
65.6	60.0	3474	1,402	-0.570	543	52.29	100.700	4.511
60.0	49.5	1802	1,166	-0.370	285	26.11	81.200	4.931
60.0	42.5	4612	1,389	-0.550	513	53.53	96.300	3.735
65.6	39.0	5022	1,370	-0.550	508	54.24	102.900	3.263
70.0	47.0	4165	1,371	-0.550	517	51.68	105.600	3.668
76.0	37.6	2218	853	-0.220	132	24.82	103.000	3.405
68.0	28.5	2701	819	-0.200	117	26.92	98.400	3.244
76.0	35.9	5414	1,329	-0.550	495	53.42	113.800	2.691
60.0	21.5	4187	1,027	-0.310	213	36.42	92.900	2.984
76.0	20.2	6998	1,346	-0.560	504	48.85	110.300	1.997
68.0	19.8	7000	1,361	-0.560	505	52.68	104.500	2.187
60.0	18.0	6998	1,382	-0.550	504	51.99	95.400	2.363
67.2	18.0	3035	849	-0.210	127	25.54	95.100	2.860
68.8	0.5	5658	886	-0.220	142	26.77	96.900	1.691
68.0	-0.1	5904	902	-0.230	149	28.06	96.900	1.703
76.0	-0.1	5978	912	-0.240	155	23.73	100.300	1.382
60.0	-3.0	5462	856	-0.200	125	27.58	89.800	1.931
61.6	-6.9	4838	792	-0.170	102	22.51	87.900	1.836
67.2	5.0	3006	695	-0.140	75	19.26	92.800	2.162
76.0	5.0	3002	616	-0.110	57	16.36	100.500	1.760

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Table 20. Test Conditions and Heat Pump Heating Performance Adjusted for Sea Level Operation in Comfort Mode

Test Conditions and Performance Data (Comfort Mode) Adjusted for Sea Level Operation								
Test Conditions			Experimental Test Result Adjusted for Sea Level Performance					
Indoor Unit Coil Conditions	Outdoor Unit Coil Conditions	Compressor Speed (RPM)	Supply Fan Flow Rate (SCFM)	External Static Pressure (in w.c)	Supply Fan Power Draw (W)	Gross Total Heating Capacity (kBtu/h)	T_db, Indoor_Supply (F)	Gross COP
Entering Dry-Bulb Temperature (°F)	Entering Dry-Bulb Temperature (°F)							
73.6	60.0	3472	1,385	-0.570	541	50.99	108.400	4.115
65.6	60.0	3474	1,402	-0.570	543	52.36	100.800	4.530
60.0	49.5	1805	808	-0.180	108	26.12	89.900	5.006
60.0	42.5	4463	1,386	-0.550	507	52.27	95.500	3.810
65.6	39.0	4708	1,357	-0.530	490	51.66	101.400	3.380
76.0	37.6	2218	650	-0.130	68	24.14	110.100	3.063
68.0	28.5	2700	721	-0.150	85	26.44	101.800	3.078
76.0	35.9	4939	1,303	-0.530	464	50.35	112.300	2.818
60.0	21.5	4178	992	-0.290	195	36.98	94.600	3.010
76.0	20.2	6001	1,258	-0.490	410	44.24	109.100	2.161
68.0	19.8	6033	1,269	-0.480	406	46.19	102.200	2.337
60.0	18.0	6118	1,245	-0.450	369	48.16	96.200	2.545
67.2	18.0	3018	807	-0.190	111	25.21	96.100	2.764
68.8	0.5	5733	889	-0.230	143	25.92	95.900	1.634
68.0	0.0	5927	906	-0.230	151	28.58	97.300	1.715
76.0	0.0	5970	909	-0.240	154	23.48	100.100	1.372
60.0	-3.0	5462	856	-0.200	126	27.89	90.200	1.952
61.6	-7.0	4790	787	-0.170	100	21.77	87.200	1.802
67.2	5.0	3022	666	-0.130	67	19.21	93.800	2.141
76.0	5.1	3014	615	-0.110	57	16.50	100.800	1.761

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

Appendix E. Accuracy of RSM Predictive Cooling Model Regressions

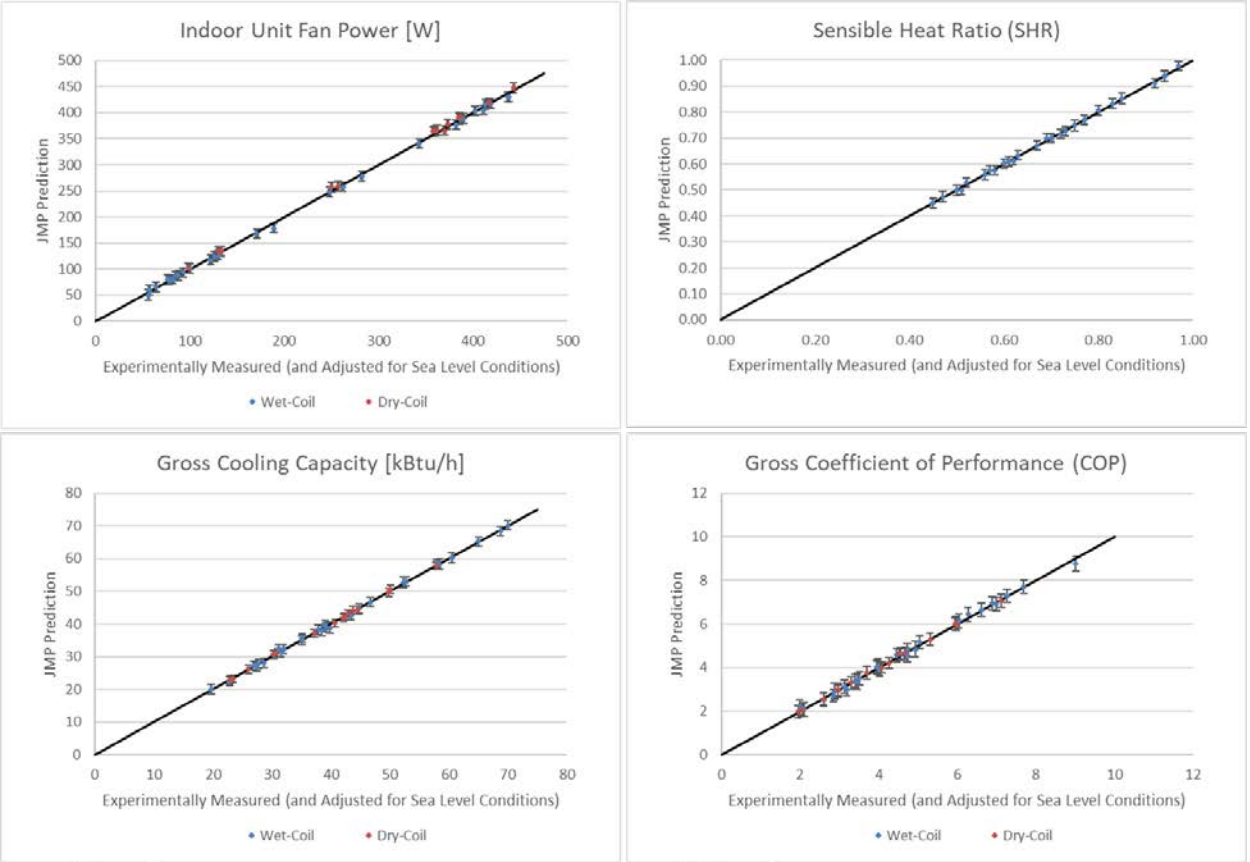

Figure 23. JMP statistical software RSM predictive model accuracy (U95) of the heat pump cooling regressions in comfort mode

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

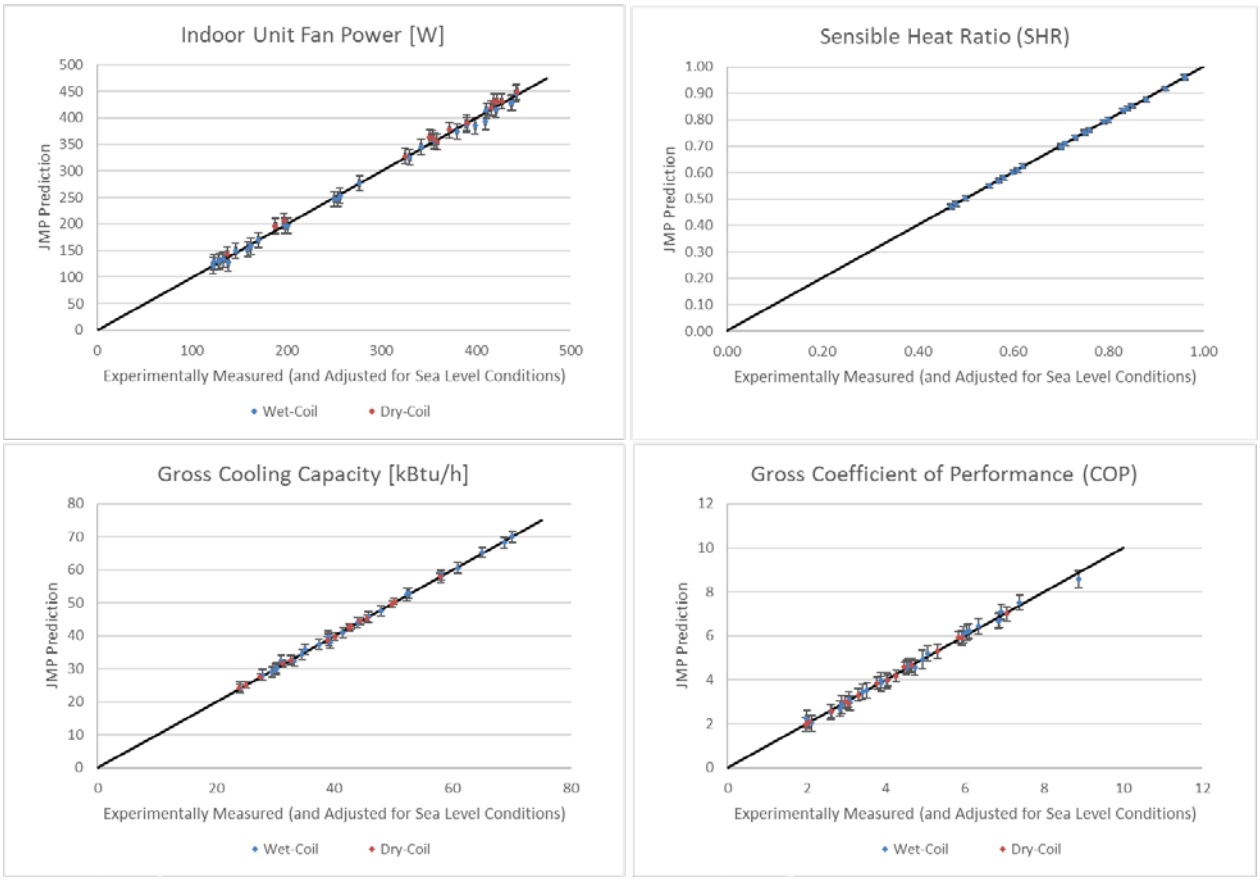

Figure 24. JMP statistical software RSM predictive model accuracy (U95) of the heat pump cooling regressions in efficiency mode

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

Appendix F. Accuracy of RSM Predictive Heating Model Regressions

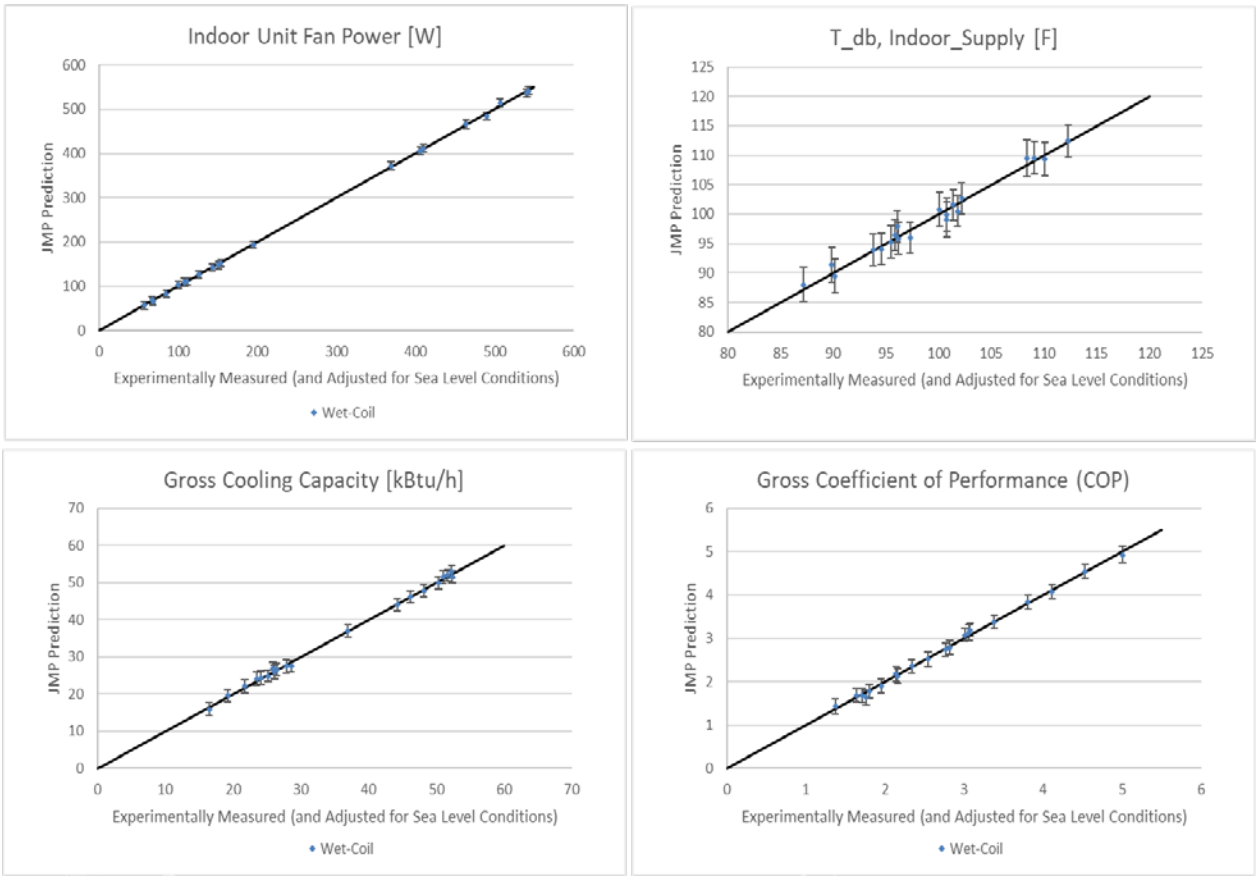

Figure 25. JMP statistical software RSM predictive model accuracy (U95) of the heat pump heating regressions in comfort mode

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

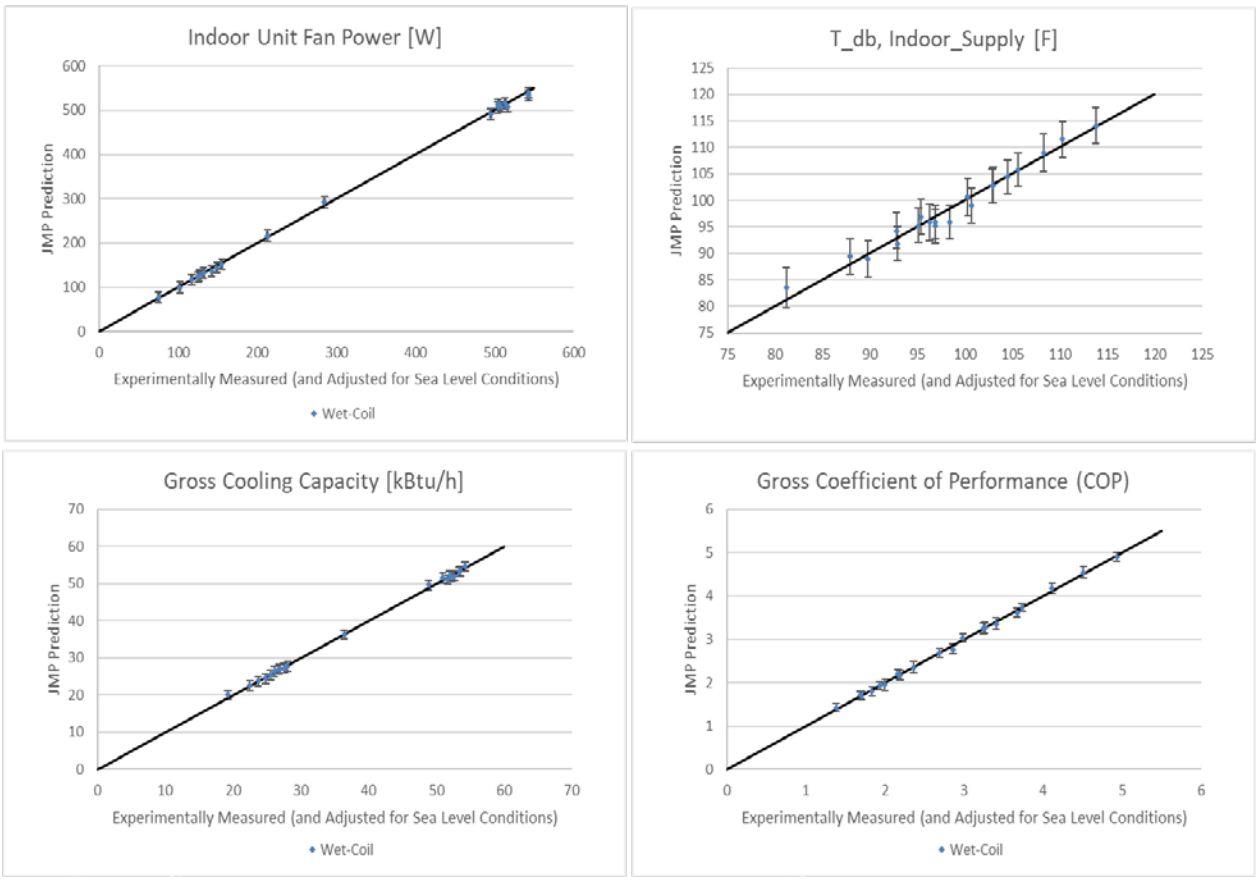

Figure 26. JMP statistical software RSM predictive model accuracy (U95) of the heat pump heating regressions in efficiency mode

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Appendix G. Heating Defrost Cycle

Defrost (25VNA0)

This user interface (UI) offers 5 possible defrost interval times: 30, 60, 90, 120 minutes, or AUTO. The default is AUTO.

Defrost interval times: 30, 60, 90, and 120 minutes or AUTO are selected by the Infinity Control User Interface (dip switches are not used.)

AUTO defrost adjusts the defrost interval time based on the last defrost time as follows:

- When defrost time <3 minutes, the next defrost interval=120 minutes.
- When defrost time 3-5 minutes, the next defrost interval=90 minutes.
- When defrost time 5-7 minutes, the next defrost interval=60 minutes.
- When defrost time >7 minutes, the next defrost interval=30 minutes.

The control board accumulates compressor run time. As the accumulated run time approaches the selected defrost interval time, the control board monitors the coil temperature sensor for a defrost demand. If a defrost demand exists, a defrost cycle will be initiated at the end of the selected time interval. A defrost demand exists when the coil temperature is at or below 32°F (0°C) for 4 minutes during the interval. If the coil temperature does not reach 32°F (0°C) within the interval, the interval timer will be reset and start over.

- Upon initial power up the first defrost interval is defaulted to 30 minutes. Remaining intervals are at selected times.
- Defrost is only allowed to occur below 50°F (10°C) outdoor ambient temperature.

The defrost cycle is terminated as described below.

- When OAT is > 25°F (-3.9 °C), defrost terminates if outdoor coil temperature (OCT) > 60°F (+15.6°C) (min. 4.5 minutes)
- When OAT is </= 25°F (-3.9°C), defrost terminates if outdoor coil temperature (OCT) > 45 °F (+7.2°C) (min. 3.25 minutes)
- Or 10 minutes has passed.

At the defrost termination, the outdoor fan output (ODF) will turn on 15 seconds before the reversing valve switching.

NOTE: Compressor speed during defrost varies based on outdoor conditions.

Figure 27. Defrost embedded control logic explained in the Carrier 25VNA0 service manual

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 78

To advise as to whether Enbridge has information from NRCan about the performance of cold-climate heat pumps; to advise Enbridge's knowledge with respect to the brands that are actually available in Canada that are effective down to minus 30.

Response:

The information available to Enbridge Gas from NRCan, as provided within this response, is sourced from publicly available NRCan materials.

The Company has interpreted the first part of the question to be requesting NRCan information on the performance of cold climate air source heat pumps (ccASHP) at winter design conditions, while meeting the consumer's needs for heating/comfort, and to illustrate the expected associated impacts on the energy system. NRCan maintains a database of eligible equipment for air source heat pumps (ASHP), including ccASHPs, which contains thousands of active options[1]. This means there are readily available ccASHP options[2] for consumers allowing electrification of space heating, including options that at least theoretically allow for disconnecting from the gas system and relying on electricity as the sole source of energy supply at the design day temperature for Toronto.

Reliability of the energy supply is of critical importance to energy consumers, particularly in cold winter conditions in Ontario. Therefore, the systems best suited for the vast majority of consumers would include not only a heat pump, but an auxiliary heat supply, which in an all-electric heating system would be an electric heating coil for a centrally ducted system as described below and based on NRCan publicly available documentation targeted to Mechanical Designers and Renovation Contractors.

[1] https://oee.nrcan.gc.ca/pml-lmp/index.cfm?language_langue=en&action=app.search-recherche&appliance=ASHP1_GH

[2] Exhibit J11.6 uses 3 examples of ccASHP models that have lab performance data for lower temperatures near the design day temperature for Toronto. Most equipment models do not have lab performance data available at these lower temperatures, even if the manufacturer states the model is cold climate or can operate to these temperatures.

NRCan published a report[3] "focused on comparing the energy costs of ccASHPs relative to conventional electric, gas and oil furnaces" which can be used as a source for information on the performance of ccASHPs in cold winter conditions. The study shows the expected peak heating loads in the Toronto location vary between 6.1 kW and 11.6 kW for existing building stock building archetypes.[4] These heat loads are based on a -20 C temperature[5], and therefore heat loads are expected to be materially higher at the -26.1 C system design temperature for Toronto. These figures represent the heat output required from the heating system to maintain indoor temperature/comfort, and therefore need to be adjusted by the efficiency/COP (coefficient of performance) of the heating system to understand the energy input into the heating system which is drawn from the energy system.

Figure 1 shows how the COP of ccASHPs drop significantly in cold winter conditions, from about 4.28 at 8 C[6] to about 1.46 at -25 C (close to the system design temperature). Figure 1 also shows how the high-capacity factor materially drops from 1.0 at 8 C to about 0.7 at -25 C, meaning the heat pump can only deliver 70% of the rated capacity at this temperature. The drop in capacity is why in the vast majority of situations (explained in more detail below) an auxiliary heating system is installed.

The share of heat supplied by the heat pump and the COP of the heat pump plus the share of heat supplied by auxiliary heating and the efficiency of the auxiliary heating (100% for an electric coil) will determine the total efficiency/COP of the heating system. For example, if at design conditions the heat pump supplies 50% of the heating requirement at a COP 1.46 and the auxiliary the remaining 50% at 100%/COP 1, the total heating system would be delivering heat at an effective COP of 1.23. A 11.6 kW heat output/peak heating requirement would result in a 9.4 kW draw from the electric grid. The sizing of the heat pump relative to the heating load will clearly impact the share of the heat pump versus auxiliary heating output, but at lower temperatures the lower COP clearly shows that there will always be a large additional load on the electric system with an all-electric heating system. Higher capacity ccASHPs can deliver a higher proportion of the heating load at colder conditions in many retrofit situations, but

[3] Cold-Climate Air Source Heat Pumps: Assessing Cost-Effectiveness, Energy Savings and Greenhouse Gas Emission Reduction in Canadian Homes. Link: https://ftp.maps.canada.ca/pub/nrcan_rncan/publications/STPublications_PublicationsST/329/329701/gid_329701.pdf
[4] Ibid, Page 10, Table 1.
[5] Ibid, Page 8, Figure 1.
[6] The stated values are for the 3 1/2 ton unit and using the Low column for higher temperatures where the capacity of the heat pump would be higher than the heat loss of the home, so the unit would be expected to be operating in the lower range. The colder temperatures where the capacity of the heat pump is expected to be lower than the heat loss, references are to the High columns, as the heat pump is expected to be operating at maximum capacity.

have technical limitations related to the sizing of existing ductwork and/or the need to upgrade the electrical panel in order to achieve the rated performance, which may increase upfront consumer costs.

Figure 1: Heat Pump Performance Table
(Appendix A from NRCan's "Cold Climate Air Source Heat Pumps" Report[7])

Appendix A: Heat Pump Performance

HP Performance data: 2 1/2 ton

Ambient	Capacity Factor		COP	
Temp.(°C)	Low	High	Low	High
-25.0	0.32	0.74	1.90	1.40
-15.0	0.41	0.94	2.24	1.76
-8.3	0.47	0.94	2.43	1.90
0.0	0.53	0.94	3.00	2.52
8.3	0.53	1.00	4.39	3.07
12.8	0.55	1.14	4.84	3.27
18.0	0.58	1.32	5.46	3.48

HP Performance data: 3 ton

Ambient	Capacity Factor		COP	
Temp.(°C)	Low	High	Low	High
-25.0	0.33	0.73	2.15	1.38
-15.0	0.38	0.95	2.54	1.82
-8.3	0.48	0.95	2.74	2.06
0.0	0.52	0.95	3.40	2.99
8.3	0.45	1.00	4.63	3.49
12.8	0.47	1.11	5.08	3.61
18.0	0.49	1.24	5.72	3.74

HP Performance data: 3 1/2 ton

Ambient	Capacity Factor		COP	
Temp.(°C)	Low	High	Low	High
-25.0	0.39	0.67	1.79	1.46
-15.0	0.39	0.89	2.25	1.91
-8.3	0.48	0.89	2.44	2.09
0.0	0.53	0.90	3.02	2.43
8.3	0.35	1.00	4.28	3.25
12.8	0.39	1.11	4.71	3.35
18.0	0.44	1.24	5.22	3.45

[7] Ibid, p. 36.

The second portion of the request is regarding what consumers are being advised by NRCan/the industry when they are making consumer decisions on heat pump installations.

There are two sources of information from NRCan that Enbridge Gas believes are most often relied upon for informing consumers: the Canada Greener Home Grant ("CGHG") heat pump eligibility listing[8] and the Air-Source Heat Pump Sizing and Selection Guide[9] ("Selection Guide"). The eligibility listing shows a wide range of ccASHP's that are eligible for rebates in the HER+ program, with the eligibility listing being maintained by NRCan for consistency across Canada. Service Organizations and Registered Energy Auditors can access the eligibility listing to inform consumers of currently eligible makes/models. At present, there are currently thousands of model numbers on the eligibility listing, providing a wide array of models to suit specific customer circumstances, which may vary significantly.

The Selection Guide is intended for use by Mechanical Designers and Renovation Contractors and as such is a technically oriented document. In Step 4, the Selection Guide lays out four sizing options for the ASHP based on the client's goals for the installation and provides examples for each option. Of the four options, only 4D targets sizing the heat pump to approximate the design heat load and describes the appropriate situations for this sizing selection as follows:

> **Option 4D**: Sites where the ASHP is the principal heating source, because the application is:
>
> · in a location where propane, fuel oil and electricity are the available fuel types (i.e., low cost natural gas is not available);
> · a new, energy-efficient home;
> · an existing home with deep energy retrofits;
> · another low-load installation, such as:
> o uses in mild heating climates;
> o small condo or house; or
> o single-zone system serving an individual room or new addition in an existing home.
>
> For most climate zones in Canada, a CC-ASHP will be required with Option 4D.

[8] This listing can be found at: https://oee.nrcan.gc.ca/pml-lmp/index.cfm?language_langue=en&action=app.search-recherche&appliance=ASHP1_GH

[9] The guide can be found at: https://natural-resources.canada.ca/sites/nrcan/files/canmetenergy/pdf/ASHP%20Sizing%20and%20Selection%20Guide%20(EN).pdf

> **Note**: Option 4D sizing may not be feasible when retrofitting centrally ducted ASHPs to existing duct systems designed for traditional furnaces. These duct systems will have a maximum airflow capacity which may limit the size of ASHP to a value below the Option 4D sizing requirement, unless significant energy improvements have been made to the thermal envelope of the house. A simple procedure for estimating maximum airflow capacity of existing duct systems is described on page 16.

Option 4D is only appropriate for a minority of the Ontario market, consisting of new homes and deep retrofits. The other options that apply to the majority of Ontario consumers would yield equipment selections that have the capacity of the ccASHP at a fraction of the design heating load and therefore require substantial reliance on auxiliary heating systems during cold winter conditions, with impacts to the energy system similar to the 9.4 kW increase described earlier, which was for space heating and did not include water heating.

Figure 2 provides an illustrative picture of what a typical ASHP installation performance might look like:

Figure 2: Typical ASHP Installation Performance
(Figure 25 from NRCan's "Air Source Heat Pump Sizing and Selection Guide"[10])

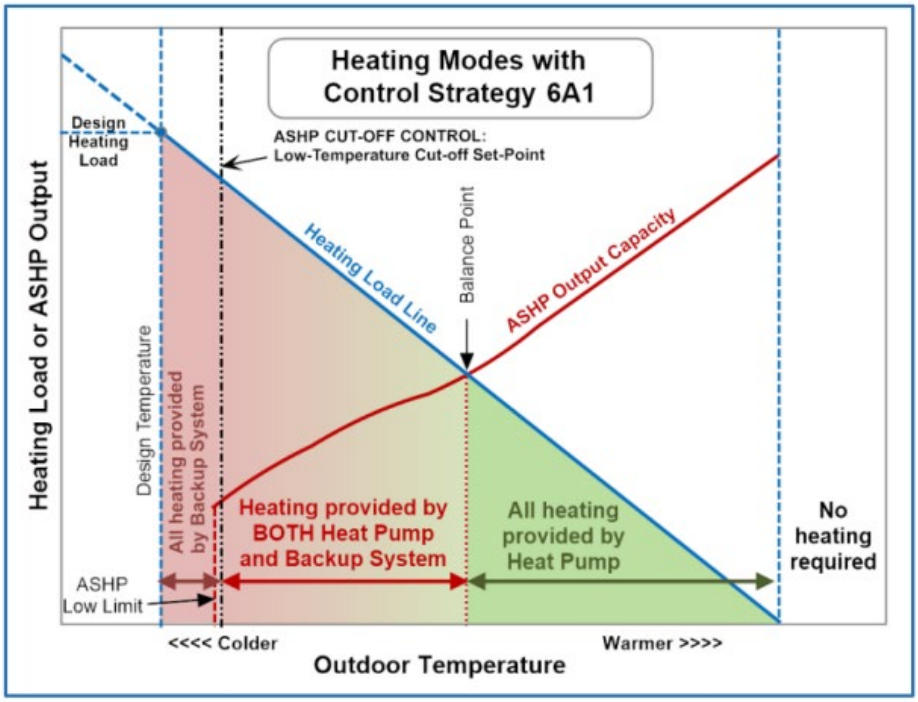


Figure 25: Example of Heating Modes with Control Strategy 6A1

The heat load of the building is shown with the blue line, which increases with lower outdoor air temperatures. The maximum output capacity of the ASHP is depicted with the red line, which as described earlier, decreases with the colder outdoor air temperatures. At outdoor temperatures above the intersection of the two lines, called the thermal balance point temperature, all heating will be provided by the ASHP, as depicted in the green shaded area. At outdoor temperatures between the thermal balance point temperature and the cut-off temperature[11], heating will be provided by both the ASHP and backup (or auxiliary) system, as depicted by the red shaded area. Significant changes to the heating load, through a building envelope improvement, would shift the blue heating line down and therefore shift the balance point to colder temperatures, with an associated cost to the consumer. Conversely, higher/lower ASHP capacity units would shift the red line up/down and shift the balance point to the left/right, with higher capacity units having higher capital costs to the consumer.

[10] Ibid, p. 35.
[11] ccASHP may have a cut-off control below the design temperature depending on the climate zone and the specific manufacturer and model

To summarize, if most consumers are being informed by installers using the NRCan ASHP Selection Guide they would most likely be installing ccASHP systems that have auxiliary heating. For an all-electric home, there would be large draws on the electric system during cold winter conditions from such installations. The impact of a number of electric conversions, such as the 100,000 consumers noted in the transcript[12], at an assumed 10 kW per consumer would be in the order of 1,000 MW of incremental winter demand for space heating alone. This number could be materially mitigated if consumers choose to perform deep energy retrofits, but they would then incur significant additional upfront costs.

Enbridge Gas also notes that references were made to the HER+ program funding for a theoretical 100,000 customers leaving the gas system and installing ccASHPs. This is unrealistic because NRCan funding is limited. That is, NRCan funding is $5000 per ccASHP; for 100,000 customers, this would require $500 million in rebates from NRCan, which is more than the entire rebate funding pool (Task 3 covering rebates for all measures in the CGHG agreement was for a total of $482.5 million) on just one of many measures the funding is intended to support. Enbridge Gas is not aware of any evidence that would support such an outcome.

Additionally, if the 1.5 million new homes proposed in the *More Homes Built Faster Act* over 10 years were all-electric, at 5 kW per home (inclusive of space heating and other loads), this would add 750 MW in electric demand each year during the 10-year period. Electrification of building heating requires examination of the impacts on the electric system, energy reliability and adequacy of energy supply which are clearly matters of public interest for consumers given Ontario winter conditions.

[12] The discussion leading up to J18.5 is just one example of the mention of 100,000 customers electrifying and leaving the gas system.

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 87

Enbridge to file the analysis comparing fuel sources as backup to heat pumps.

Response:

Enbridge Gas interprets the analysis requested in Tr. Vol.11 pages 86 to 87 as a request to compare the GHG emissions from a gas furnace to a ccASHP with auxiliary electric resistance heating during a peak winter hour. It was also indicated that during peak winter conditions a large portion of electricity demand is provided from gas-fired generation. A reference was given to a report produced by Power Advisory to calculate marginal emissions from the electricity grid as well. Please find this report at Attachment 1.

As discussed in Exhibit J11.5, the efficiency and the heating capacity of electric air source heat pumps drops significantly at very low ambient temperatures, thereby necessitating auxiliary heating during peak winter conditions to meet the residual heating demand not supplied by the heat pump and maintain a comfortable temperature inside the home.

To illustrate the impact on emissions, the Company provides the following illustrative analysis and emphasizes that the actual performance of any ccASHP will depend on a variety of factors, many of which are specific to the customer's home, and they can all materially impact the operation, efficiency, costs and impacts on the electric grid.

The performance and the heating capacity of an air source heat pump drops as the outdoor temperature drops, as illustrated in Figure 1. If the temperature continues to drop, there will be a point (the crossover temperature or balance point) at which the ccASHP capacity drops below the home heating demand and the auxiliary electric resistance heating (in an all-electric home) will be required to meet the residual heating demand and maintain the desired temperature inside the home. The crossover temperature at which the auxiliary heat comes on varies with the size and type of heat pump installed and the characteristics of the home. Although it may be feasible to provide all of the heating load with a ccASHP, it may not be practical or cost effective.

For the retrofit market this could require significant building envelope upgrades, upgrading the electrical panel and service and/or upgrading the entire ducting system to handle larger volumes of air. Similarly, for new construction, an all-electric heating system will require incremental electricity generation capacity from the grid necessitating grid system planners to take the winter peak design conditions into consideration.

The following illustrative example demonstrates the complexity of the question by varying only the installed ccASHP model and using either manufacturer or Northeast Energy Efficiency Partnership (NEEP) database information where it is available to the Company.[1]

Example detached home

Existing furnace capacity:	60,000 Btuh (5 tons)
Existing air conditioner:	24,000 Btuh (2 tons)
Heating design load (@approx -25C/-13F) [2]	48,000 Btuh (4 tons)

The following use cases demonstrate what an all-electric centrally ducted space heating system expected performance might be with three different manufacturers' units. The units were selected solely based on the availability of information for the specific models at lower temperatures[3] sourced from either manufacturer specs, or the NEEP database and it should be noted the selected models represent higher performing units.

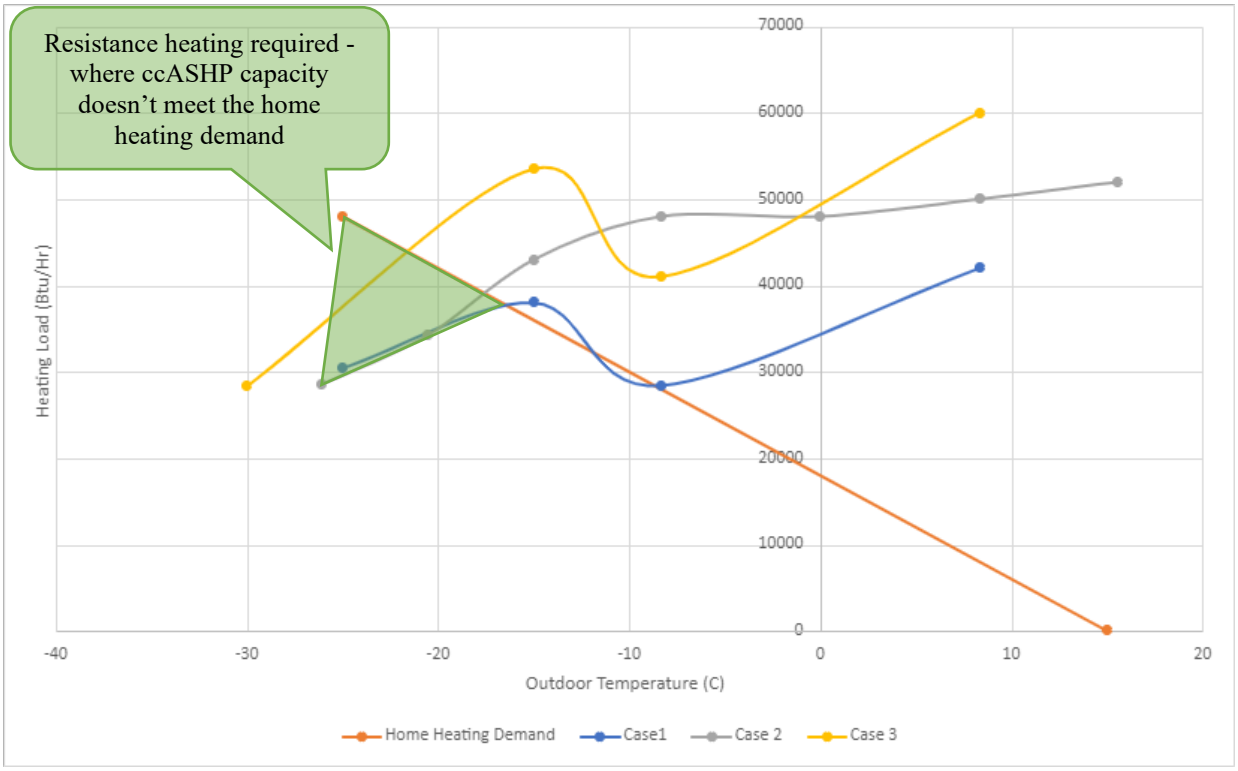
Use Case 1: Install a 3.5 ton/42,000 Btuh rated ccASHP Mitsubishi PUZ-HA36NKA*
Use Case 2: Install a 4 ton/48,000 Btuh rated ccASHP Napoleon model no. NPFX48A / NS18HV48A60A
Use Case 3: Install a 5 ton/60,000 Btuh rated ccASHP Cooper & Hunter CH-NHPR60LCU-230VO

The performance specifications for the ccASHP models can be found at Attachment 2.

[1] The NEEP database has very few models with information shown below a 5F/-15C temperature. Manufacturers information on performance also rarely lists information below these temperatures as well. The examples used are models where the information was found to be available. The list should not be taken to be inclusive of all models available.
[2] The Company has assumed a 125% oversizing in this illustrative example. NRCan publishes a guide for sizing and selection of ASHP which can be found at Air-source Heat Pump Sizing and Selection Guide (canada.ca) which lists alternate methods. The guide is targeted to mechanical designers and renovation contractors.
[3] The majority of manufacturer specifications and the listings in the NEEP database only list performance criteria down to 5F/-15C. The company has selected units that have lower temperature performance information available that is in the range of what sizing options 4C or 4D would yield in the sizing and selection guide in footnote 2

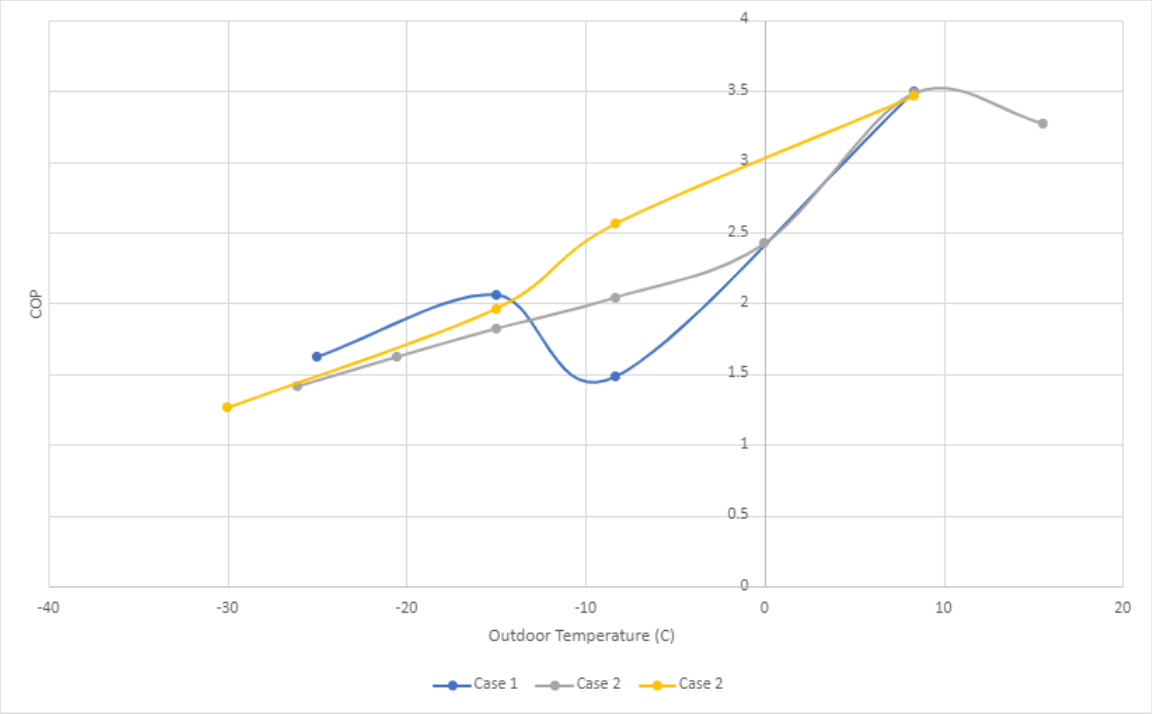
Figure 1 displays the capacity of each ccASHP and how the capacity changes with respect to outdoor temperature. In all cases the capacity (and coefficient of performance or COP) degrades with lower temperatures. Where the heating demand curve intersects the ccASHP capacity curve is when the supplementary electric resistance heating will be required. In all three cases, electric resistance heating was required for peak winter design condition.

Figure 1 :Heating Demand and Heat Pump Capacity Curves vs. Outdoor Air Temperature



The corresponding coefficient of performance (COP) or heating efficiency for each of these units is shown in Figure 2 to demonstrate the drop in performance with respect to temperature. It should be noted that these values reflect lab tested COP and heating capacity that do not reflect the impact of defrosting cycles that can be expected to further degrade performance.

Figure 2: Heat Pump COP vs. Outdoor Air Temperature



The performance and capacity degradation with lower temperatures is shown for the three cases in Table 1 below. As the COP drops, so does the capacity. The balance of the 48,000 Btuh heating load will need to be made up with auxiliary electric resistance for an all-electric heating system. The electric resistance power requirements coupled with the heat pump input power gives a total electric system impact of between 10.67kW and 12.35kW from space heating alone at ambient air temperature ranging from -25ºC to -30ºC. In addition, many consumers would require an electric panel upgrade to accommodate this heating system.

Table 1
Heat Pump Performance Characteristics

	COP @ 8C	COP[4]	Capacity Btu/hr @ 8C	Capacity Btu/hr /kW[5]	Electric Resistance Heating (Btu/hr / kW)	Total Electric Impact (kW)
Case 1	3.49	1.62	42,000	30,400 / 5.51	17,600 / 5.16	10.67
Case 2	3.48	1.41	50,000	28,500 / 5.91	19,500 / 5.71	11.61
Case 3	3.46	1.26	60,000	28,300 / 6.58	19,700 / 5.77	12.35

[4] COP is shown at temperatures of -25ºC, -26.1ºC, and -30ºC for Case 1, 2 and 3 respectively
[5] Capacity is shown at temperatures of -25ºC, -26.1ºC, and -30ºC for Case 1, 2 and 3 respectively

In summary, all of these models, when coupled with auxiliary electric heating and heat-pump water heaters (that draw heat energy from inside the home to heat the domestic water), would materially increase the design heating load, while reducing the cooling design load in the summer. Substantive changes in the heating load would drive large changes in the amount of load served by auxiliary electric resistance. In all cases there would be a large impact on the electric grid at design heating conditions compared to a gas heated home or a hybrid gas/electric system.

Analysis shows that the emissions from a gas furnace or hybrid gas/electric system will be much lower as compared to a ccASHP with electric resistance heating as a backup during a peak winter hour. This analysis is summarized in Table 2, and the Excel version is provided at Attachment 3.

Table 2
Peak Heating Hour Emissions from Air Source Heat Pump Auxiliary Electric heating compared to a Gas Furnace:

Furnace capacity	Btu/hr	60,000
Furnace efficiency	%	95
Peak heating load	Btu/hr	48,000
	kWh	14.07

		Use Case 1	Use Case 2	Use Case 3
cc-ASHP size	ton	3.5	4	5
	Btu/hr	42,000	48,000	60,000
Capacity[6]	Btu/hr	30,400	28,500	28,300
COP[7]		1.62	1.41	1.26
Backup heating (Resistance) efficiency	%	100	100	100
Heating load supplied by ASHP	Btu/hr	30,400	28,500	28,300
Electricity power consumption by ASHP	kW	5.5	5.9	6.6
Electricity energy consumption by ASHP for one peak hour	kWh	5.5	5.9	6.6
Heating load supplied by Resistance heating	Btu/hr	17,600	19,500	19,700

[6] Capacity is shown at temperatures of -25ºC, -26.1ºC, and -30ºC for Case 1, 2 and 3 respectively
[7] COP is shown at temperatures of -25ºC, -26.1ºC, and -30ºC for Case 1, 2 and 3 respectively

Electricity power consumption by Resistance heating	kW	5.16	5.72	5.77
Electricity energy consumption by Resistance heating for one peak hour	kWh	5.16	5.72	5.77
Total electricity energy consumption	kWh	10.66	11.64	12.36
Grid marginal emissions for ASHP + Electric backup	**kg CO2e**	**4.49**	**4.90**	**5.21**

Furnace peak hour gas consumption	Btu/hr	50,526	50,526	50,526
	m3/hr	1.4	1.4	1.4
Emissions from a furnace	**kg CO2e**	**2.6**	**2.6**	**2.6**

Emission Factors

Power Advisory grid Marginal Emission Factor for peak Winter Months		421	g CO2e/kWh
Gas furnace emission factor		1.9	kg CO2e/m3
		175	g CO2e /kWh

Load duration curves were developed in order to determine how often gas plants were running in order to supply Ontario demand, during the winter months (Dec 1- Mar 31) for 5 years from 2018-2022. Load duration curves for winter 2022 are shown in Figures 3 and Figure 4 [8]to illustrate that gas-fired plants were running during every hour during the winter months to meet electricity demand. Similar load duration curves are shown under tab “Load Duration Curves” at Attachment 3. The analysis also showed that a large portion of Ontario electricity demand was met by gas-fired plants during peak winter conditions. For example, in 2021 gas-fired generation supplied up to 34% of Ontario’s demand (December 8 at 16:00 hour). This percentage would increase as new resistance heating load is added to the grid, which will also result in greater GHG emissions.

[8] source: https://www.ieso.ca/en/Power-Data/Data-Directory

Figure 3: Load Duration Curves by Forms of Generation for 2022

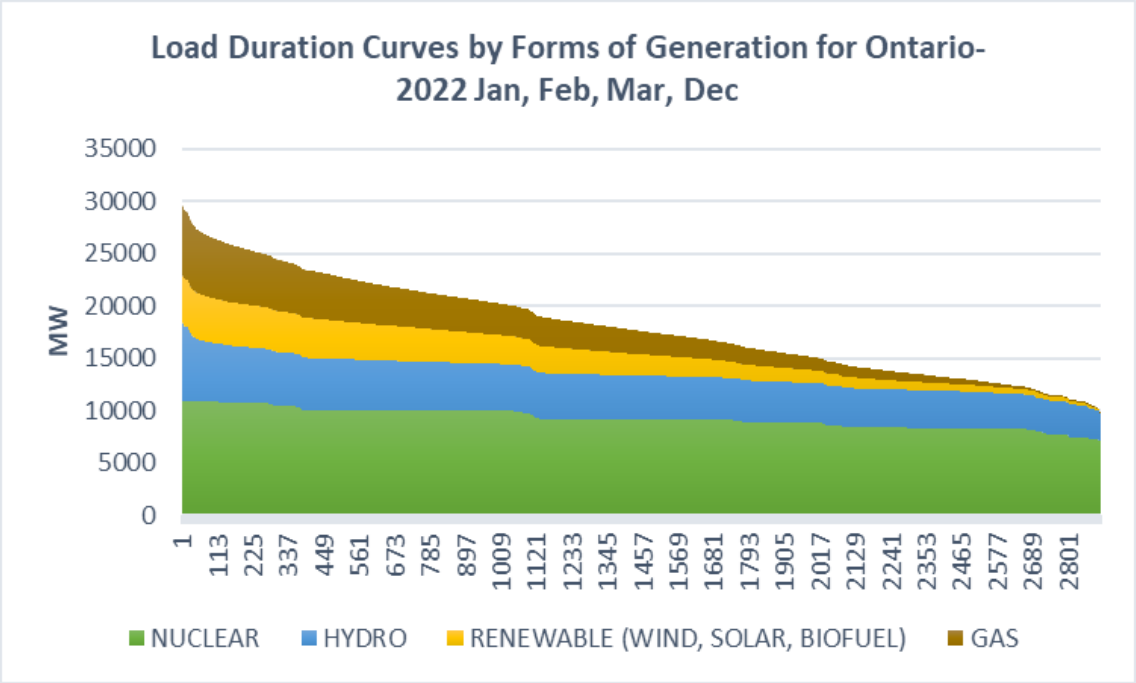
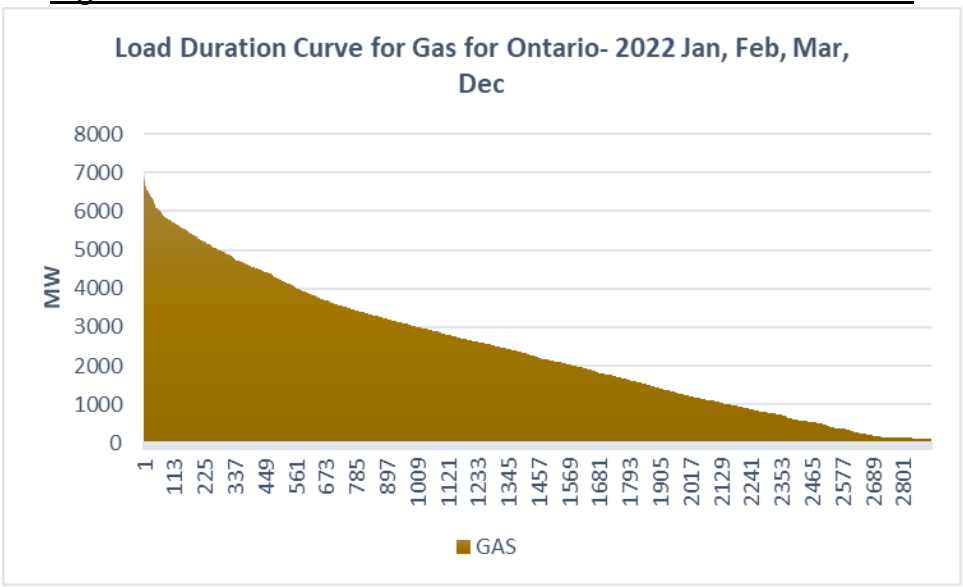


Figure 4: Load Duration Curves for Gas Generation for 2022



In order to fully respond to the undertaking, the Company also provides a comparative analysis of the backup required for a gas furnace or hybrid gas/electric system versus a ccASHP system to run in the event of a power outage. For this analysis, the Company

has compared the performance of battery storage behind the meter, such as a Tesla Powerwall (a single Powerwall has an output of 5kW and a capacity of 13.5kWh).

For example, the ccASHP with auxiliary resistance heating requires 10kW – 13 kW whereas the gas furnace or hybrid gas/electric system only requires about 0.4 kW to operate the furnace fans. Where a Tesla Powerwall or other similar battery is installed to back up the heating system only. At peak design load, a furnace running on one Powerwall could continuously provide 48,000Btu/hr for approximately 33 hours. A ccASHP with auxiliary resistance heat at peak design load would require two Powerwalls and together the two batteries would only provide two to three hours of continuous heating. In addition, if the heating load is more than 10kW a third Powerwall would be required to supply the necessary power, which may result in requiring a Connection Impact Assessment by the local LDC, translating to additional costs.

As shown, modifications to make a home resilient with a gas furnace, including a hybrid gas/electric system, can be made more simply and affordably than for an all-electric system that would require a much larger battery storage system.

Marginal Greenhouse Gas Emission Factors for Ontario

Electricity Generation and Consumption

Prepared for:

Enbridge Gas Inc.

October 2020

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Executive Summary

Broadly, the objective of climate change policy for energy use is to reduce the amount of greenhouse gas emissions produced while meeting the energy need of the consumer. Greenhouse gas emission factors indicate the volume of emissions attributable to a unit of energy use or activity. Two types of emission factors, namely Average Emission Factors (AEFs) and Marginal Emission Factors (MEFs), are used to evaluate the impact of various technologies, policies and program.

Use of the appropriate type of emission factors is essential. Using AEFs to assess policy or programs in the electricity sector can produce misleading results because AEFs do not consider the time-dependant impacts of electricity generation and consumption; MEFs are better suited for this purpose. When assessing policy and program, it is important to understand the relationship between fuel consumption, electricity generation and electricity consumption on an hourly, daily and seasonal basis. A misinterpretation of these factors could lead to unintended consequences that could result in a net increase in GHG emissions. For example, electrification of space heating increases electricity consumption during peak demand periods when MEFs could be much higher than AEFs – an important factor in evaluating net GHG emission impacts.

This report documents Power Advisory's estimates of MEFs for electricity generation and consumption for Ontario. The objective of this report is to provide Ontario stakeholders with an overview of Power Advisory's marginal emissions factor methodology and guidelines for their use. Ultimately, the goal of the report is to provide clarity and confidence for use when assessing activities that could reduce greenhouse gas emissions in Ontario.

Power Advisory's marginal emission factor estimates are based on the relationship between Ontario demand; gas-fired generation; energy production from all sources of generations; and imports & exports with neighbouring jurisdictions. Most of Ontario's generation (i.e., nuclear, hydro, wind, solar and bioenergy) has no emissions; therefore, emissions due to Ontario's electricity system come from two main sources:

- Natural gas-fired generators in Ontario
- Emissions associated with electricity imports.

The MEFs account for emissions from both gas-fired generation located in Ontario and imports from neighbouring jurisdictions, including how these inputs will change over time due to refurbishment of nuclear fleet and shutting down of Pickering nuclear station.

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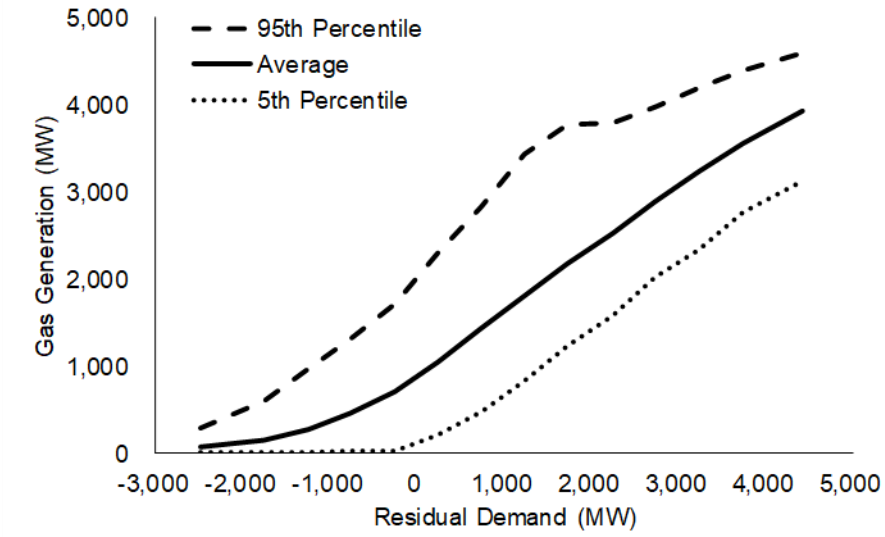
The process for estimating emission factors involved several steps:

1. Forecast demand and less flexible generation (nuclear, some hydroelectric, wind, solar and bioenergy) for each hour in the forecast period and calculate the difference between the two, which is referred to as Residual Demand
2. Quantify the relationship between Residual Demand and Fossil Generation & Net Imports (i.e., gas-fired generation)
3. For each hour of the forecast period, estimate the impact that a 1-MWh change in Residual Demand would have on Fossil Generation, Net Imports, and GHG emissions

The results of the analysis produce the following relationship between Residual Demand and Fossil generation in Ontario (see figure below). Change in Residual Demand in each hour results in a change of Fossil Generation. The difference in Fossil Generation between the initial and final Residual Demand for a given hour is the net impact on greenhouse gas emissions.



Hourly Fossil Generation vs. Residual Demand, base years 2015-2019

Ontario's fleet of large gas generators is estimated to have a GHG emission factor of 0.412 tonnes/MWh. The MEF varies between 0 and 0.412 tonnes/MWh, depending upon the above correlation. Power Advisory forecasted MEFs for every hour from 2020 – 2040. Contact information to get this data file is available at the end of this report. The MEFs are also summarized by both season and time-of-use period for the forecasted period of 2020 – 2040. The overall MEF for all 20 years is projected to be 0.32 tonnes/MWh.

Overall, Power Advisory hopes this report and the marginal emission factor estimates will assist stakeholders in determining the optimal strategy for reduce greenhouse gas emissions.

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1. INTRODUCTION

1.1 The Importance and Use of Marginal Emission Factors

There is a growing global consensus for the reduction of greenhouse gas (GHG) emission to combat the negative impacts of climate change. Many measures have been proposed to reduce GHG emissions. For example, replacing incandescent light bulbs with high-efficiency Light Emitting Diodes (LEDs), reduces the use of electricity and the emissions associated with generating that electricity. On the other hand, replacing cars powered by conventional gasoline engines with plug-in electric vehicles (PEVs) increases the use of electricity (and the emissions associated with generating electricity). However, net emissions may decrease if the reduction of emissions from gasoline engines is greater than the increase in emission from greater electricity production. It is important to understand the relationship between fuel consumption, electricity generation and electricity consumption on an hourly, daily and seasonal basis. A misinterpretation of these factors could lead to unintended consequences that could result in a net increase in GHG emissions.

Greenhouse gas emission factors indicate the amount of emissions attributable to a unit of energy use or activity. Two types of emission factors are commonly used:

- **Average Emission Factors** (AEFs) are the ratio of all emissions resulting from a certain activity (e.g., transportation, or electricity consumption) to some measure of that activity (e.g., kilometers travelled, or MWh consumed). The primary use of Average Emission Factors is to develop inventories of GHG emissions – i.e., total emissions and where they come from.
- **Marginal Emission Factors** (MEFs), which are the subject of this report, are used to evaluate specific policies or programs. MEFs are the ratio of the increase or decrease in GHG emissions resulting from a unit change. An example would be the net change in emissions from driving one kilometer in a PEV instead of a gasoline-powered vehicle.

Use of the appropriate type of GHG emission factors is essential. Using AEFs to assess policy or programs can produce misleading results because AEFs do not consider the time-dependant impacts of electricity generation and consumption; MEFs are better suited for this purpose. When assessing policy and program, it is important to consider time of use. For example, electrification of space heating increases electricity consumption during peak demand periods when MEFs could be much higher than AEFs – an important factor in evaluating net GHG emission impacts.

This report documents Power Advisory's estimates of MEFs for electricity generation and consumption. The emission estimates are intended for use in evaluating programs, policies and other activities that depend, partially or fully, on electricity supplied from the Ontario electricity grid. The emission factor analysis and this report were developed by Power Advisory under an engagement with Enbridge Gas Inc. The analysis and report reflect Power Advisory's independent views and extensive knowledge of the Ontario electricity sector.

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1.2 Ontario's Electricity System and Outlook

Ontario's bulk electricity system and electricity market are operated by the Independent Electricity System Operator (IESO). The IESO-Administered Market (IAM) supplies Ontario consumers with approximately 135 TWh of electricity through the transmission system; a further 6 TWh/year is generated by embedded generation (i.e., distributed generation delivered to consumers through local distribution systems). Ontario's electricity generation output by fuel type for 2019 is shown in Figure 1 and electricity generation by installed capacity in Figure 2.

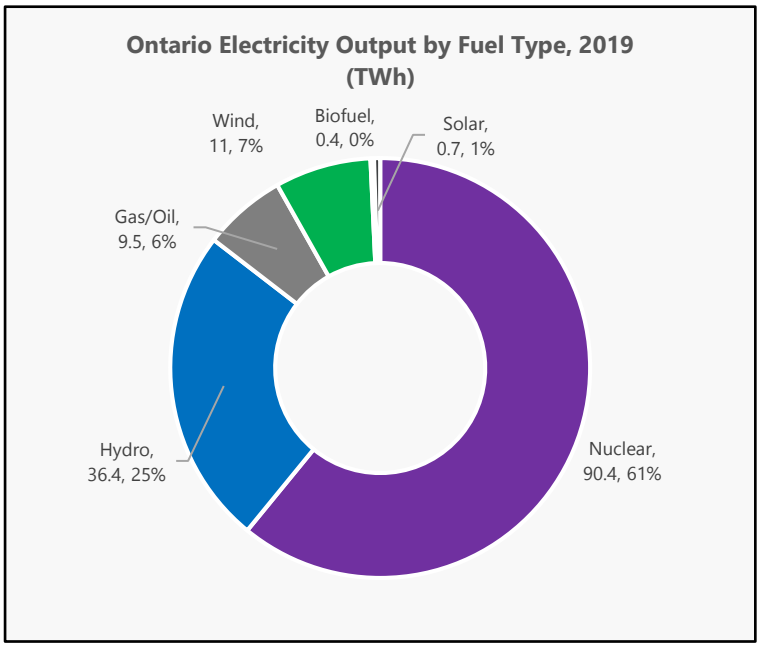

Figure 1: Ontario 2019 Electricity Output by Fuel Type (TWh)[1]

More than half of Ontario's electricity supply comes from three nuclear stations: Pickering, Darlington and Bruce Power. In addition, there has been a surplus of supply in Ontario over most of the past decade. Supply surplus results in reduced usage of gas-fired generation assets that are commonly used to meet peaking demand needs.

Ontario's electricity supply mix is expected to change over the next two decades. The Pickering Nuclear Station is scheduled to retire at the end of 2025 and 10 nuclear generation units at Bruce Power and Darlington will be taken out of service for refurbishment[1]. Each unit will be out of service for up to 4 years and as many as four units may be out at one time. During the refurbishment, gas-fired generation will operate more often to replace energy from the out-of-service nuclear units. Figure 3 below shows Power Advisory's forecast of Ontario supply and demand.

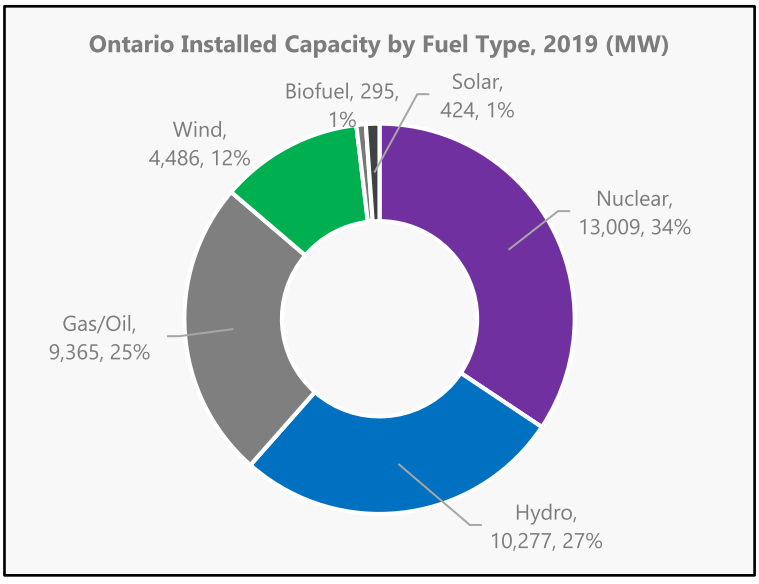

Figure 2: Ontario 2019 Installed Capacity by Fuel Type (MW)[1]

[1] Information on the refurbishment projects can be found for Darlington at https://www.opg.com/strengthening-the-economy/our-projects/darlington-refurbishment/, and for Bruce at https://www.brucepower.com/life-extension-program-mcr-project/ .

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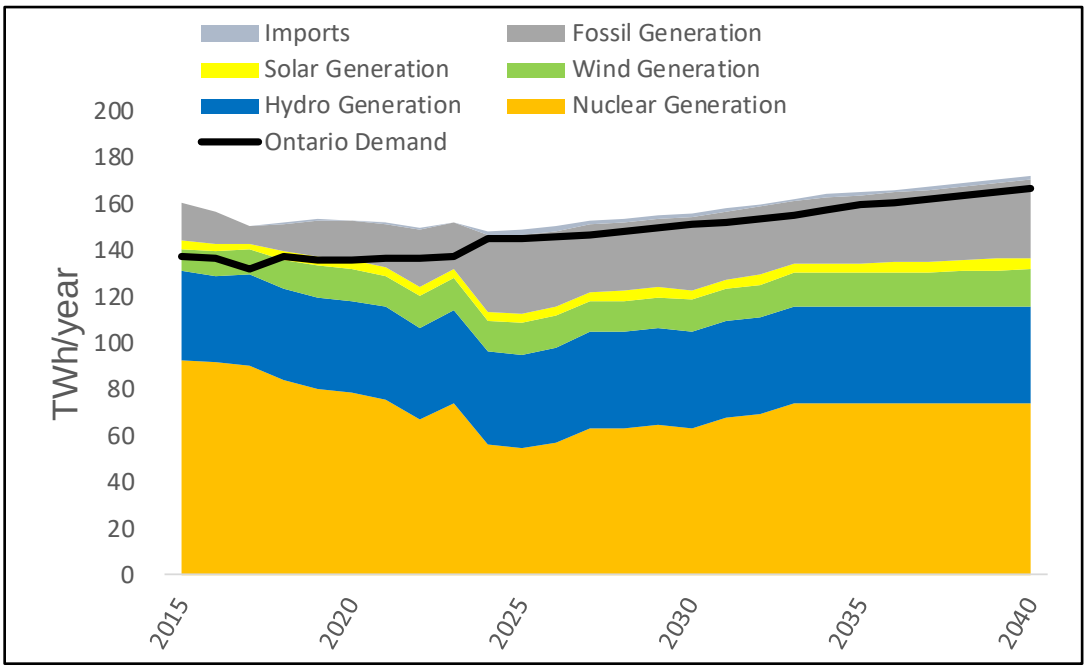

Figure 3: Ontario Electric Energy Supply and Demand

Most of Ontario's generation (i.e., nuclear, hydro, wind, solar and bioenergy) has no emissions; therefore, emissions due to Ontario's electricity system come from two main sources:

- Natural gas-fired generators in Ontario
- Emissions associated with electricity imports.

Natural gas-fired generation currently supplies only a moderate share (around 12%) of Ontario's electric energy, but it plays a crucial role in balancing supply and demand. For example, when the IESO schedules supply for dispatch to meet forecasted demand they must ensure that there is enough generation that can ramp (i.e., increase or decrease output) fast enough to follow variations in electricity consumption patterns. In Ontario, ramping primarily comes from gas-fired generation and hydroelectric generation.

Ontario's electricity grid is well interconnected with neighbouring jurisdictions across 26 interties to two provinces (i.e., Manitoba and Quebec) and three states (i.e., Minnesota, Michigan and New York). Ontario schedules imports and exports on an hourly basis. Depending on the source of imports they can be considered to increase Ontario's GHG emissions.

The MEFs developed by Power Advisory account for emissions from both gas-fired generation located in Ontario and imports from neighbouring jurisdictions, including how these inputs will change over time.

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2. METHODOLOGY

2.1 Overview

GHG emissions in Ontario's electricity system come from two main sources: gas-fired generators in Ontario, and emissions associated with electricity imports from other jurisdictions. In general, both tend to be high when demand is high or less flexible generation[2] is low, and both tend to be low when demand is low or less flexible generation is high. The relationship is not exact: hours with very similar demand and supply of less flexible generation can see very different amounts of both gas-fired generation and imports. These differences are due to a number of factors:

- Gas-fired generation attributes (e.g., ramp rate) and maintenance schedules (e.g., planned outages);
- The availability and price of imports; and
- The availability of export opportunities (e.g., gas-fired generation output exported to higher price neighbouring jurisdictions in a given hour).

Power Advisory's MEF estimates are based on quantifying and extrapolating these patterns. The process for estimating emission factors involved several steps:

1. Forecast demand and less flexible generation for each hour in the forecast period and calculate the difference between the two, which is referred to as Residual Demand[3]
2. Quantify the relationship between Residual Demand and Gas Generation[4]
3. For each hour of the forecast period, estimate the impact that a 1-MW change in Residual Demand would have on Gas Generation, Net Imports[5], and GHG emissions

[2] Less flexible generation is defined as the sum of transmission-connected nuclear, hydroelectric, wind, solar and bioenergy projects; it also excludes embedded generation. A case could be made for distinguishing between baseload and peaking hydro, treating the latter separately rather than including it in less flexible generation. However, as discussed in a footnote 11 below, this would not significantly affect the results.

[3] For the purposes of this report, "**Residual Demand**" is defined as Ontario electricity demand minus less flexible generation. All amounts are hourly, and historical values are based on data published by the IESO. Ontario Demand is reported in the IESO's Ontario and Market Demand reports. Hourly generation for almost all of Ontario's transmission-connected generators is reported in the IESO's Generator Capability and Output reports. Both sets of reports are available at http://ieso.ca/en/Power-Data/Data-Directory in the "Featured Reports" section.

[4] Fossil Generation is defined as transmission-connected generation using natural gas, oil or coal as fuel.

[5] Net Imports is imports into Ontario minus exports out of Ontario. In many hours it is negative (i.e., exports exceed imports).

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The following sections describe each step in more detail. The resulting hourly MEFs can either be summarized by hour of the day, season, time-of-use period, etc., or used as is for more detailed analysis.

2.2 Step 1: Residual Demand

Residual Demand represents the imbalance between Ontario's need for electricity (at the transmission level) and what is available from its own nuclear, hydro, wind, solar and bioenergy generators. This imbalance can come from only two sources: Gas Generation and Net Imports. In many hours, Residual Demand is negative, meaning that even if there were no Gas Generation in that hour, Ontario would have a surplus available for export.

Power Advisory maintains a wholesale market forecast model that forecasts hourly operation of Ontario's electricity system. The wholesale market forecast model includes an electricity demand forecast and a supply forecast. Residual Demand is calculated as the difference between forecast Ontario electricity demand and forecast less flexible generation. Table 1 below summarizes the primary inputs for the forecast model

Table 1: Forecast of Residual Demand Inputs

Demand Forecast Inputs	Supply Forecast Inputs
• Organic growth in electricity demand; • Expected levels of conservation and demand management; and • Growth in demand from emerging technologies (e.g., electric vehicles and heat pumps).	• The availability of Ontario's nuclear fleet (i.e., retirement and refurbishment); • Existing generation including Ontario Power Generation's (OPG's) rate-regulated assets and generation currently under contract with the IESO; • Committed contracts for transmission-connected generators not yet in service; and • Development of new generation to meet supply adequacy needs.

Not all gas-fired generation is dispatchable: there are some cogeneration facilities that run almost all hours of the year to supply thermal energy to their load hosts. Some of these facilities have both a constant, baseload level of generation in virtually all hours, and dispatchable capacity above this baseload level operates primarily when Residual Demand is high. Power Advisory's analysis included identifying those facilities and estimating how much of their generation in each hour of 2015-2019 was baseload vs. dispatchable. Baseload generation was added to less flexible generation (which means it reduced Residual Demand). Only dispatchable generation was included in Gas Generation with the following attributes:

- At very low levels of Residual Demand, (dispatchable) Gas Generation falls to zero.
- Dispatchable generation affects forecasts of Residual Demand. Several cogeneration facilities retired or converted to dispatchable-only operation during the 2015-2019

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period when their original Power Purchase Agreements expired. All of the remaining gas-fired generators with a baseload component are expected to retire, or convert to dispatchable-only operation, during the forecast period.

2.3 Step 2: Relationship Between Residual Demand and Gas Generation

On average, electricity production by Gas Generation increases as demand increases and power from less flexible generation (such as nuclear and renewables) decreases. To quantify this relationship, all hours from Base Years[6] were grouped based on Residual Demand in that hour (i.e., all hours with Residual Demand less than -2,000 MWh were put in one group, all hours with Residual Demand between -2,000 and -1,500 MWh in another group, etc.).[7] For each group, both average Residual Demand and average Gas Generation was calculated. The results are shown in Figure 4 below; the 5th and 95th percentile of Gas Generation in each group are shown for reference.

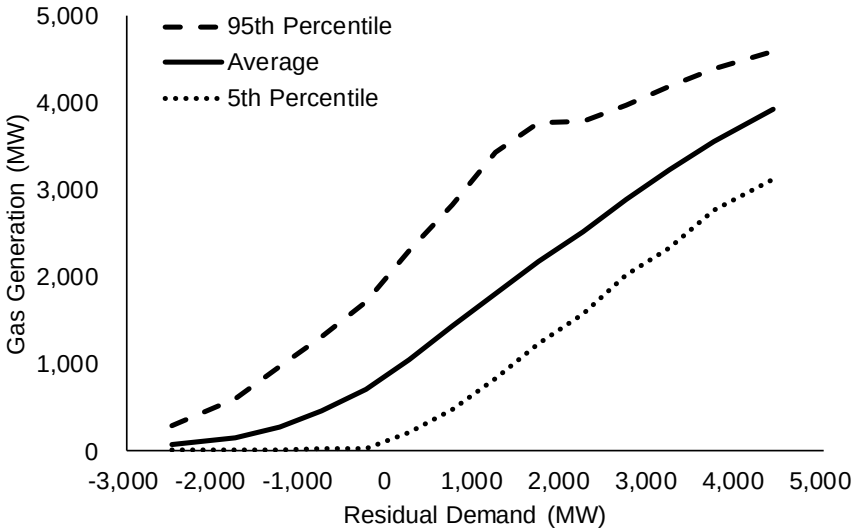

Figure 4: Hourly Gas Generation vs. Residual Demand, 2015-2019

[6] Five Base Years (2015-2019) were used to represent a range of supply, demand, weather and price scenarios. Years earlier than 2015 are considered less indicative of current and future market operations because of market rule and other changes.

[7] The use of 500-MWh intervals was selected for a balance between precision and accuracy. Smaller intervals would have provided more detailed information about the shape of the curve; however, if the intervals were too small there would not be enough hours to provide a meanful average within each group.

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The resulting curve from the Gas Generation and Residual Demand relationship has an S-shape:

- When Residual Demand is low, the slope of the curve is quite shallow; at very low levels, the curve is flat, with a slope of zero. Within this group of hours, reductions in Residual Demand have little correlation with Gas Generation. Instead, Ontario's electricity system adjusts through either higher exports or increased curtailment of internal supply (i.e., nuclear, hydro, wind and solar).
- The slope of the curve is highest at intermediate levels of Residual Demand, reflecting that fact that gas-fired generation is dispatched to serve growing demand.
- At high levels of Residual Demand, the slope decreases slightly. There is a limit to how much Ontario gas-fired generators can produce; any additional supply needs must be met by importing electricity from other jurisdictions.

The resulting curve of average Gas Generation vs. average Residual Demand in each group can be approximated closely to a series of four straight lines (shown in red on Figure 5 below):

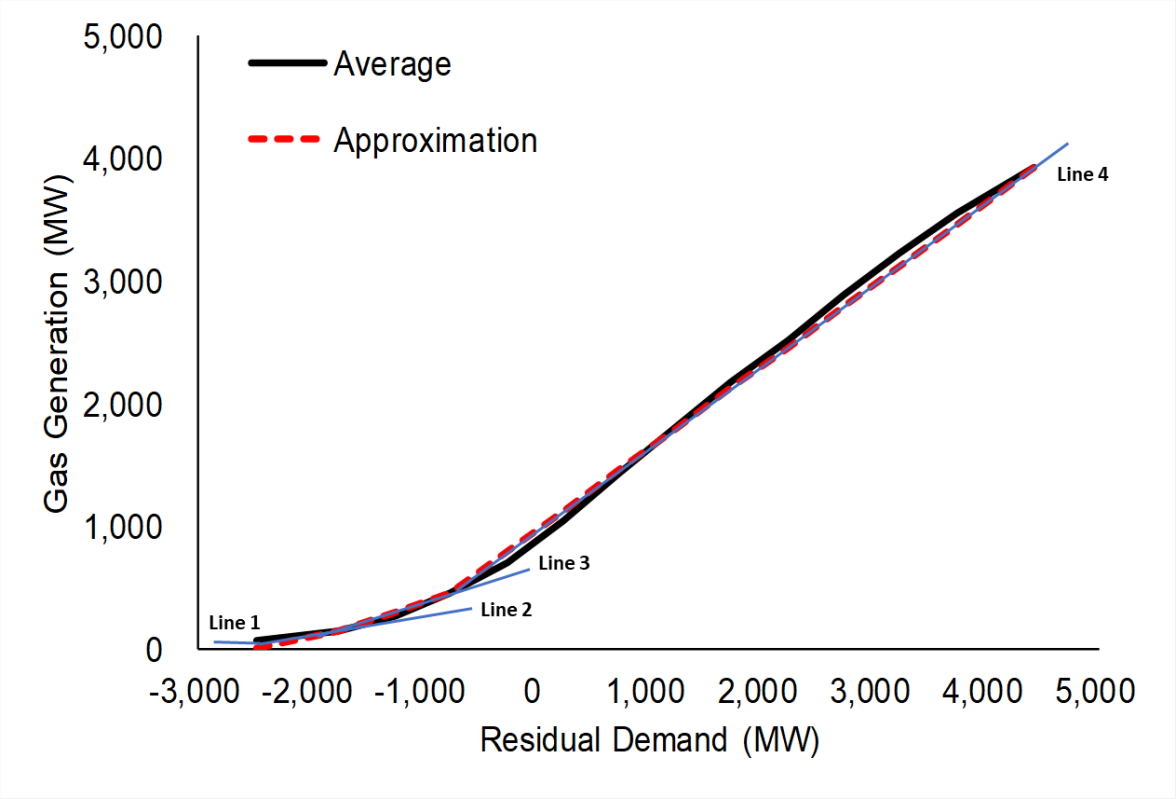

Figure 5: Approximation of Gas Generation vs. Residual Demand

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- Line 1 for Residual Demand below -2,500 MW, with a slope of zero (i.e., changes in Residual Demand do not result in changes in Gas Generation);
- Line 2 for Residual Demand between -2,500 and -1,750 MW, with a slope of 0.19 (i.e., Gas Generation increases by 0.19 MW for each 1-MW increase in Residual Demand);
- Line 3 for Residual Demand between -1,750 and -750 MW, with a slope of 0.32; and
- Line 4 for Residual Demand above -750 MW, with a slope of 0.67.

The slopes of each line segment show how Gas Generation changes in response to changes in Residual Demand. In addition, the line segments show how Net Imports change because Residual Demand is equal to Gas Generation plus Net Imports. For example, at the low end (in the range covered by Line 2), a 1-MWh increase in consumption (or a 1-MWh decrease in less flexible generation) is met by a 0.19-MWh increase in Gas Generation and a 0.81-MWh increase in Net Imports. In the high range (Line 4), a 1-MW increase in demand is met by a 0.67-MWh increase in Gas Generation plus a 0.33-MWh increase in Net Imports.

2.4 Step 3: Forecast Gas Generation, Net Imports and GHG Emissions

Ontario's fleet of large gas generators is estimated to have an emission factor of 0.412 tonnes/MWh, meaning that every 1 MWh increase (or decrease) in gas generation increases (or decreases) GHG emissions by, on average, 0.412 tonnes. This emission factor was derived by dividing the fleet's total emissions by its total output for the five Base Years (2015-2019), as shown in Table 2. The input data was taken from two sets of IESO data:

- The IESO's 2020 Annual Planning Outlook,[8] Figure 32 provides estimates of historical electricity sector GHG emissions. During the five Base Years, the only fossil fuel used in significant amounts in transmission-level generation was natural gas.
- The IESO's "Generator Output and Capability Reports[9] provide information on the actual output of all transmission-connected generation plants over 10 MW, including all significant gas generators.

[8] http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook. The data used to create the figure is available in spreadsheet form.

[9] http://reports.ieso.ca/public/GenOutputCapability/. Only 90 days of historical data is available on-line, but additional data can be obtaining by contacting the IESO's Customer Service department.

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Table 2: Emission Factor for Ontario Gas Generation

Base Year	Electricity Sector GHG Emissions (million tonnes)	Gas Generation (TWh)	Emission Factor (tonnes/MWh)
2015	6.3	15.66	0.402
2016	5.5	13.01	0.423
2017	2.5	6.07	0.412
2018	4.0	9.88	0.405
2019	4.1	9.84	0.417
Average	**4.5**	**10.89**	**0.412**

Ontario's two least efficient gas plants, Lennox and York Energy Centre, operated very rarely in the Base Years, but are expected to operate much more frequently over the forecast period as nuclear retirement and refurbishment decreases baseload supply and increases Residual Demand. It could be argued that a higher gas emission factor should be used at very high levels of Residual Demand, when these two plants tend to come on-line contributing to higher emissions. This factor has not been factored into the MEF calculations.

An emission factor was also estimated for imports. Emission factors for imports from neighbouring jurisdictions could be derived from the supply mix in those jurisdictions (e.g., Quebec's generation resources are primarily hydroelectric). This approach however does not recognize the flow of electricity across multiple jurisdictions. Ontario is part of the eastern interconnection that includes electricity network across the eastern part of Canada and the US. The eastern interconnection supplies over 700 GW of electricity demand and has robust electricity trade between jurisdictions. From a broader geographical perspective, every MWh of electricity that one jurisdiction exports to Ontario, especially during peak demand hours, is less electricity that could be exported to another jurisdictions. In addition, imports to Ontario are a function of market dynamics in neighbouring jurisdictions in addition to market opportunities for electricity trade with Ontario. Determining specific import expectations by neighbouring jurisdictions would require detailed outlooks for each neighbouring jurisdiction in addition to potentially other jurisdictions within the eastern interconnect. That undertaking would be overly complex. Instead, Power Advisory has assumed a global view of emission factors for imports to Ontario that is an amalgamation of supply mixes across neighbouring jurisdictions.

Power Advisory estimated a series of emission factors attributable to net imports. The starting point was as 2017 report produced to support Ontario's Cap and Trade Program,[10] which

[10] "2017 Default Emission Factors for Ontario's Cap and Trade Program", available at https://www.ontario.ca/document/default-emission-factors-ontarios-cap-and-trade-program/2017-default-emission-factors. Although these emission factors no longer have any legal effect because Ontario's cap-and-trade program has been cancelled, the research and analysis on which the estimates were based remain valid.

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estimated emission factors for each of the jurisdictions surrounding Ontario. For 2020, a weighted average of the on-peak emission factors was calculated, using as weights the peak demand of each jurisdiction; the result was 0.58 tonnes/MWh (i.e., each MWh of imported electricity when imports exceed exports is assumed to result in 0.58 tonnes of GHG emissions). For later years, the calculations recognized that these emission factors are likely to fall, both because coal generation (which contributed to the high emission factors for MISO and PJM) is being phased out, and that there will be some development of true carbon-free peaking capacity (such as batteries charged with carbon-free electricity). Import emission factors are reduced to 0.17 tonnes/MWh by 2050. Exports were assumed to have no impact on the emissions attributable to Ontario.[11]

For each hour in the Forecast Period, the Residual Demand for that hour (estimated in Step 1 above) and the four line segments that approximate the relationship between Gas Generation and Residual Demand (developed in Step 2 above) were combined to estimate a typical level of Gas Generation for that hour. Net Imports for each hour were then calculated as the difference between Residual Demand and Gas Generation.[12] This was used to determine whether the province was forecast to be a net importer or a net exporter in that hour, which is a significant factor in the calculations below.

For each hour, marginal emissions from a 1-MWh increase (or decrease) in Residual Demand was estimated by calculating marginal emissions from the associated increase in Gas Generation and, if Net Imports were positive, the marginal emissions associated with imports. As an example, consider an hour in which Residual Demand is 1000 MW. Using Line 4 for the approximation, Gas Generation is estimated to be 1,632 MW. Subtracting Gas Generation from Residual Demand, Net Imports are estimated to be minus 632 MW, and the province is assumed to be a net exporter. The marginal emission factor from Gas Generation is 0.67 MWh of Gas Generation per MWh of Residual Demand (the slope of Line 4) times 0.412 tonnes of GHG emissions per MWh of Gas Generation. This gives a marginal emission factor of (0.67 x 0.412= 0.28) tonnes of GHG emissions per MWh of Residual Demand.

Imports are assumed to contribute to Ontario's marginal emissions only when Net Imports is positive, which occurs only when Residual Demand is very high – specifically, when it exceeds

[11] Ontario exports of low or no emissions electricity generation may reduce emissions in neighbouring jurisdictions to which they are delivered, but these were not credited to Ontario.

[12] This implicitly assumes that when Residual Demand is very high, such that Ontario is importing more than it is exporting, there are only two sources of supply to meet a further increase in Residual Demand: additional fossil generation and additional imports. As noted in a footnote above, it could be argued that peaking hydroelectric generation should be treated as a third potential source of supply, rather than being including in less flexible generation. However, Power Advisory analysis has found that hydro generation in Ontario reaches its peak when Residual Demand is approximately 2,000 MW, well less than the level at which net imports become positive. In general, when Residual Demand reaches 4,000 MW or higher, all available peaking hydro is already operating, leaving fossil generation and imports as the only remaining sources of significant amounts of additional supply.

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2,900 MW. At that point, each 1-MWh increase in Residual Demand is estimated to increase Gas Generation by 0.67 MWh (the slope of Line 4, which applies when Residual Demand is greater than -750 MW); the rest of the increase in Residual Demand is met by a 0.33-MWh increase in imports.

Each hour in each year was assigned to one of five possible values. As an example, the possible values for 2030 are shown in Table 3 below, based on the import marginal emission factor for that year (0.44 tonnes/MWh).

Table 3: Ontario MEF by Residual Demand Range

Range of Residual Demand	Marginal Emissions from Gas Generation (tonnes/MWh)	Marginal Emissions from Imports (tonnes/MWh)	Ontario MEF (tonnes/MWh)
Less than -2,500 MWh	0	0	0.00
-2,500 to -1,750 MWh	0.19 x 0.412 = 0.08	0	0.08
-1,750 to -750 MWh	0.32 x 0.412 = 0.13	0	0.13
-750 to 2,900 MWh	0.67 x 0.412 = 0.28	0	0.28
Greater than 2,900MWh	0.67 x 0.412 = 0.28	0.33 x 0.44 =0.15	0.42

One of these five emission factors (0.00, 0.08, 0.13, 0.28, or 0.42 tonnes/MWh) is assigned to each forecast hour, depending on the forecast of Residual Demand in that hour. (The fifth emission factor will vary by year because the import marginal emission factor is forecast to decline over time.) These emission factors represent typical changes in emissions due to changes in either demand or Less Flexible Generation under the expected system conditions.

2.5 Other Methodologies for Estimating Marginal Emission Factors

At least two other estimates of MEFs for Ontario's electricity system have been produced, one by the IESO[13], the other by The Atmospheric Fund (TAF), an agency of the City of Toronto[14]. Both produce estimates that are significantly lower than Power Advisory's estimates, but both suffer from methodological flaws.

- The IESO's estimates are based on a model of Ontario's electricity system that does not accurately reflect how gas generation is dispatched in real-time. In practice, it is normal for large amounts of gas-fired capacity to be operating even when the province's

[13] http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/APO-Avoided-Emissions-2020.xlsx?la=en. Power Advisory's understanding of the IESO's methodology for calculating marginal emission factors is based on a telephone conversation with Mike Risavy, Manager, Reporting & Economic Analysis, Power System Planning, on April 30, 2020, and by analysis of the published results.

[14] https://taf.ca/publications/a-clearer-view-on-ontarios-emissions-2019/

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baseload generation exceeds its demand, but the IESO's model does not reflect this. As well, the IESO does not attribute any emissions to imports, with the result that in some years, MEFs during peak hours are forecast to be much lower than those in off-peak hours.

- TAF uses historical data to estimate MEFs, but their analysis identifies the marginal resource in each hour based on only increases in generation. For example, if wind speed, and thus wind generation, increase across the province, then wind is identified as the (or one of the) marginal resource(s) in that hour, resulting in a very low MEF for that hour. In reality, wind generation is essentially a given (except that it can be curtailed in certain conditions), and any change in consumption or generation would displace gas generation or imports, not wind. TAF also does not attribute any emissions to imports.

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3. MARGINAL EMISSION FACTOR ESTIMATES AND APPLICATIONS

3.1 Mean Marginal Emission Factors

The marginal emission factor estimates resulting from the above methodology can be summarized in different ways for different applications. For example, the mean MEF in 2020 is forecast to be 0.17 tonnes/MWh, as shown in Table 4 below. The averages in that table were calculated giving equal weight to all hours in each year. The mean MEF across all hours would be useful in evaluating a program or activity that would have the same effect in all hours. However, most activities vary based on time of day, weather, season and other factors, so evaluation should take these differences into account.

Figure 6 below shows MEFs in 2020 averaged by season and hour of the day. MEFs for this particular year are expected to be highest in the summer (except early morning) and lowest in the spring. In all seasons, there is significant variation by time of day, with the highest MEFs occurring in the early evening.

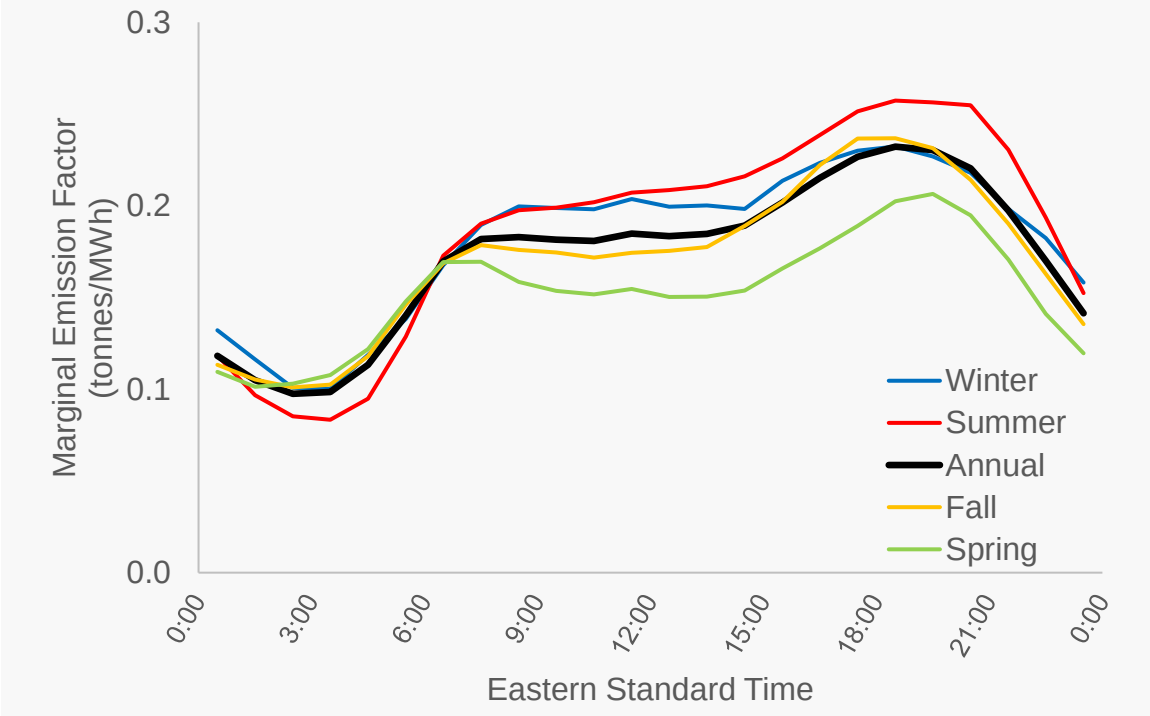

Figure 6: Marginal Emission Factors Averaged by Season and Time of Day, 2020

MEFs will change over time as Ontario's demand and generation supply changes. Figure 7 below shows mean MEFs over the forecast period. Mean MEFs are expected to jump in 2025 when the

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Pickering nuclear station retires; that will greatly reduce Less Flexible Generation and increase Residual Demand, which in turn will increase Gas Generation and imports in many hours.

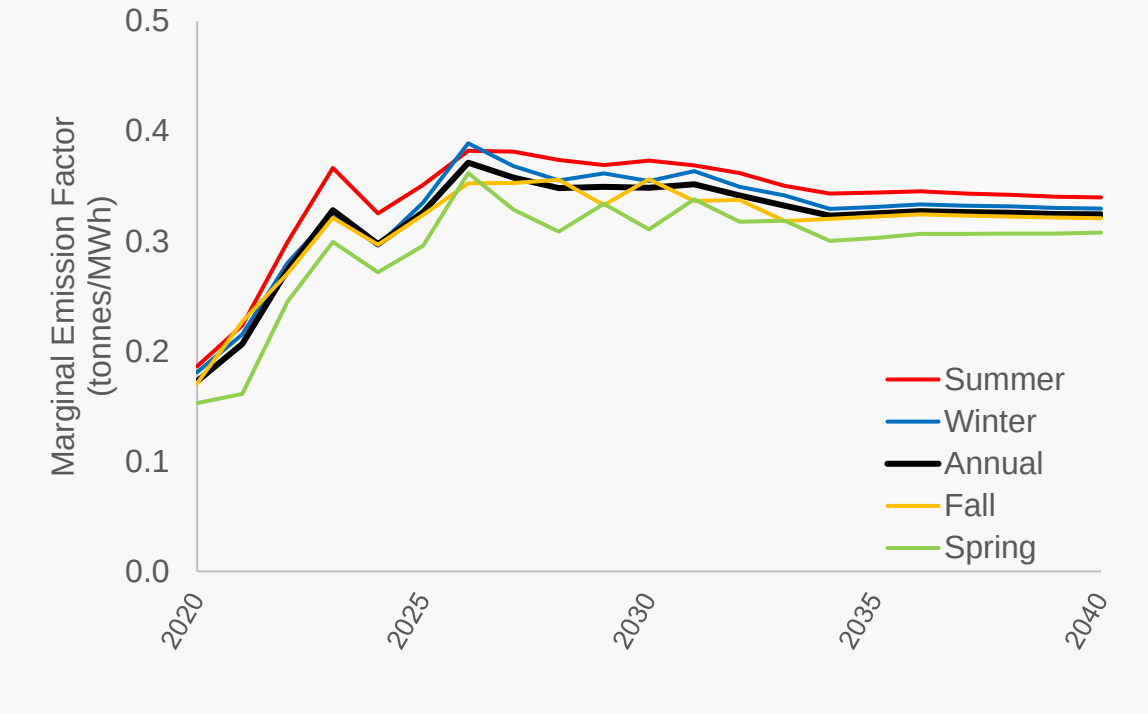

Figure 7: Marginal Emission Factors Averaged by Season, 2020-2040

Table 5 below summarizes MEFs by both season and time-of-use period. Each forecast hour was assigned to one of eight periods:

- Winter (December-March)
  1. On-Peak
  2. Mid-Peak
  3. Off-Peak
- Summer (June-September)
  4. On-Peak
  5. Mid-Peak
  6. Off-Peak
- Shoulder (April, May, October, November)
  7. On- and Mid-Peak Combined
  8. Off-Peak

Time-of-Use periods are based on those used by the Regulated Price Plan, taking into account Daylight Savings Time and the change in the on-peak/mid-peak schedule on May 1 and November 1. Forecast hours were assigned to time-of-use periods based on the Base Year, not the Forecast Year. (The hourly demand patterns used in these calculations reflect the weekends

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and holidays in the Base Years, not the Forecast Years. For example, January 4, 2022 will be a Tuesday, but when using the 2015 Base Year, demand on January 4, 2022 will be estimated based on what actual hourly demand was on January 4, 2015, which was a Sunday. The emission factors for January 4, 2022 are therefore included in the off-peak period when using the 2015 Base Year.)

Table 4: Forecast Marginal Emission Factors by Season and Time-of-Use Period (tonne/MWh)

	Winter			Summer			Shoulder		All
	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	On&Mid	Off-Peak	Hours
2020	0.21	0.21	0.15	0.21	0.20	0.17	0.17	0.16	**0.17**
2021	0.23	0.22	0.20	0.24	0.24	0.21	0.20	0.19	**0.21**
2022	0.30	0.28	0.27	0.31	0.30	0.28	0.26	0.25	**0.27**
2023	0.34	0.33	0.31	0.38	0.38	0.35	0.31	0.30	**0.33**
2024	0.32	0.30	0.29	0.34	0.33	0.31	0.29	0.27	**0.30**
2025	0.35	0.34	0.32	0.37	0.36	0.33	0.31	0.30	**0.33**
2026	0.41	0.40	0.38	0.40	0.39	0.37	0.36	0.34	**0.37**
2027	0.38	0.38	0.35	0.40	0.39	0.37	0.35	0.33	**0.36**
2028	0.37	0.36	0.34	0.39	0.39	0.36	0.34	0.32	**0.35**
2029	0.38	0.37	0.35	0.38	0.38	0.35	0.34	0.32	**0.35**
2030	0.37	0.36	0.34	0.39	0.38	0.36	0.34	0.32	**0.35**
2031	0.38	0.37	0.35	0.38	0.38	0.35	0.34	0.33	**0.35**
2032	0.36	0.36	0.34	0.38	0.37	0.35	0.33	0.32	**0.34**
2033	0.36	0.35	0.33	0.36	0.36	0.33	0.32	0.31	**0.33**
2034	0.34	0.33	0.32	0.36	0.35	0.33	0.31	0.30	**0.32**
2035	0.35	0.33	0.32	0.36	0.35	0.33	0.32	0.31	**0.33**
2036	0.35	0.34	0.32	0.36	0.36	0.33	0.32	0.31	**0.33**
2037	0.35	0.34	0.32	0.35	0.35	0.33	0.32	0.31	**0.33**
2038	0.35	0.34	0.32	0.35	0.35	0.33	0.32	0.31	**0.33**
2039	0.34	0.33	0.32	0.35	0.35	0.33	0.32	0.31	**0.32**
2040	0.34	0.33	0.32	0.35	0.35	0.33	0.32	0.31	**0.32**
All Years	**0.34**	**0.33**	**0.31**	**0.35**	**0.35**	**0.32**	**0.31**	**0.30**	**0.32**

When used to evaluate distribution-level activities (e.g., DG-CHP), adjustments should be made to account for transmission and distribution losses.

3.2 How Marginal Emission Factors Are Being Used

3.2.1 Example: Combined Heat and Power for a New High-Rise Building

A Combined Heat and Power (CHP) is an energy efficient technology that generates electricity and captures the heat that would otherwise be wasted to provide useful thermal energy—such as steam or hot water—that can be used for space heating, domestic hot water, and in some

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application space cooling, and even industrial processes. A CHP system is typically located at facilities where there is a coincident need for both electricity and thermal energy.

Nearly two-thirds of the energy used by conventional grid thermal electricity generation is wasted in the form of heat discharged to the atmosphere or a nearby lake or river. Additional energy is wasted during the distribution of electricity to end users. By capturing and using heat that would otherwise be wasted, and by avoiding distribution losses, CHP can achieve efficiencies of over 75%, compared to about 56% for conventional electricity generation and an on-site boiler. The concept of how CHP saves GHG emissions as compared to separate heat and power (SHP) is illustrated in Figure 8.

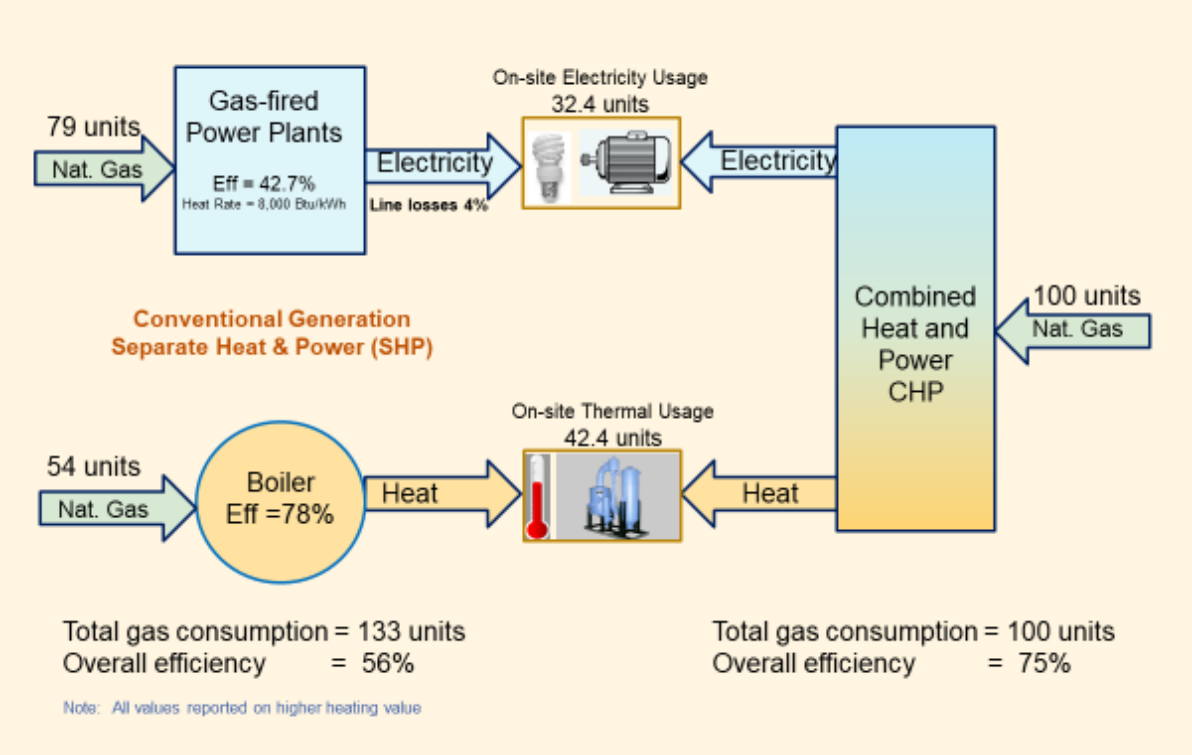

Figure 8: Efficiency of Combined Heat and Power vs. Separate Heat and Power

A case study was performed to evaluate the GHG emissions savings for installing a CHP system at a multi-unit residential building (MURB) using MEFs. An hourly simulation was performed for six scenario to provide 100% of domestic hot water (DHW) load and varying amounts of space heating loads to evaluate net GHG emission change for a proposed building with CHP as compared to a reference building with no CHP, consuming electricity supplied by the grid and

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thermal energy supplied by boilers. The analysis was performed by PowerGENySYS[15] using the hourly marginal emission factors calculated by Power Advisory. The results are summarized in Table 5 below. The analysis shows that a well-designed CHP for high-rise buildings is capable of reducing GHG emissions in all six scenarios. With the use of a single annual average emission factor and without considering future changes in electricity grid emissions, the outcome would have been different. This example shows how important is it to use the MEFs instead of AEFs for new construction.

Table 5: Case Study Results: Multi-Unit Residential Building

No.	CHP Configuration/Size		Thermal Load		Annual Outputs					GHG Emissions over 20 Yrs		
	Internal Combustion Engine (ICE) CHP Plant Configuration	Capacity, kW	DHW, %	Space Heating, %	Operating Hours	Electricity Generation, kWhr	Heat Recovery, mmBTU	Heat Utilized, %	Heat Dump, %	NET Total Emissions Change (OVER 20 YRS) tonnes	NET Avg. Annual Emissions Change, (OVER 20 YRS) tonnes/yr	Meets SB-10 CO2e Emissions Requirement
1	1 x 24 kW	24	100%	0%	7,545	181,078	1,228	99.8%	0.2%	-1,259	-62.95	YES
2	2 x 24 kW	48	100%	25%	6,662	319,793	2,169	95.7%	4.3%	-1,458	-72.90	YES
3	3 x 24 kW	72	100%	50%	6,313	448,482	3,042	88.9%	11.1%	-1,355	-67.75	YES
4	1 x 125 kW	125	100%	60%	4,696	497,847	3,230	81.1%	18.9%	-1,056	-52.82	YES
5	1 x 125 kW	125	100%	70%	4,760	504,656	3,274	81.8%	18.2%	-1,181	-59.04	YES
6	1 x 175 kW	175	100%	100%	2,087	247,228	1,395	81.1%	18.9%	-1,538	-76.92	YES

Source: Combined Heat and Power Systems for New Part 3 Multi-Family Residential Building Designed to Meet SB-10, Division 3, Chapter 1 Emission Requirements: Final Report for Municipal Building Officials, by Sustainable Buildings Canada, January 20, 2020.

[15] POWER GENySYS is a Canadian engineering firm specializing in Combined Heat and Power (CHP) and Combined Heat & Emergency Power (CHeP) systems.

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4. GUIDELINES FOR USING MARGINAL EMISSION FACTORS

When using the MEFs developed by Power Advisory, the guidelines below should be followed:

- MEFs should be used to evaluate the incremental impacts of activities, policies, programs, and measures. To develop inventories of total emissions, AEFs should be used. Power Advisory has not developed AEFs.
- Evaluation of future activities should use forecasts of MEFs that incorporate expected changes in Ontario's electricity system (e.g., changes in supply mix and demand). Using current or historic MEFs would not adequately reflect the future impact of activities. For example, Ontario's MEFs are expected to increase significantly when the Pickering Nuclear Station retires at the end of 2025.
- Summary MEFs (means over time of day, season, time-of-use period etc.) can be used for preliminary analysis of an activity. For more detailed analysis, hourly MEFs should be used. Hourly MEFs for system conditions for five corresponding Base Years (i.e., 2015-2019) are provided. Each set of hourly MEFs can be paired with historical hourly weather and electricity demand data for the corresponding Base Year. To accurately calculate emission impacts, it is recommended that each set of hourly data be used independently, and the results averaged as a final step. Contact information for obtaining hourly MEFs is provided below.
- When evaluating measures that affect supply or demand at the distribution level, such as conservation programs or distributed generation, MEFs should be adjusted for distribution losses. Total distribution losses averaged across all hours are typically around 4%, so when evaluating distribution-level measures, the MEFs could be increased by 4% as a first approximation. This adjustment could be refined based on local[16] and/or time-of-use differences, if information is available.

To obtain the hourly marginal emission factors, please contact:

Aqeel Zaidi, P.Eng.
Supervisor, Technology and Development
Enbridge Gas Inc.
500 Consumers Road, North York, M2J 1P8
Email: aqeel.zaidi @enbridge.com
www.enbridgegas.com

[16] Loss Factors for each of Ontario's Local Distribution Utilities are set by the Ontario Energy Board and published as part of the utilities' rate schedules, which are available at https://www.oeb.ca/industry/applications-oeb/electricity-distribution-rates. These represent average losses for all consumption. Different loss factors are used for small and large customers.

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Performance Specifications for ccASHP Models

Use Case 1 (from NEEP database):

AHRI Certificate # 210435439

Performance Specs

Heating / Cooling	Outdoor Dry Bulb	Indoor Dry Bulb	Unit	Min	Rated	Max
Cooling	95°F	80°F	Btu/h	16,600	36,000	36,000
			kW	1.09	3.27	3.27
			COP	4.46	3.23	3.23
Cooling	82°F	80°F	Btu/h	17,200	-	38,100
			kW	1	-	2.73
			COP	5.04	-	4.09
Heating	47°F	70°F	Btu/h	20,500	42,000	38,000
			kW	1.34	3.53	3.53
			COP	4.48	3.49	3.15
Heating	17°F	70°F	Btu/h	14,200	28,400	28,200
			kW	1.3	5.64	3
			COP	3.2	1.48	2.75
Heating	5°F	70°F	Btu/h	12,000	-	38,000
			kW	1.2	-	5.4
			COP	2.93	-	2.06
Heating	-13°F	70°F	Btu/h	11,500	-	30,400
			kW	1.22	-	5.51
			COP	2.76	-	1.62

Use Case 2 (from manufacturer):

HEATING PERFORMANCE

Outdoor Ambient Temperature (DB)		Return Air Temperature 60°F(15°C)				70°F(21°C)				80°F(27°C)			
		TC (BtuH)	Input Power (watts)	COP		TC (BtuH)	Input Power (watts)	COP		TC (BtuH)	Input Power (watts)	COP	
MAX OUTPUT	-22°F	26660	5580	1.40		26400	5700	1.36		25870	5750	1.32	
	-15°F	28780	5780	1.46		28500	5900	1.41		27930	5960	1.37	
	-5°F	34540	6070	1.67		34200	6200	1.62		33510	6260	1.57	
	5°F	43430	6780	1.88		43000	6920	1.82		42140	6990	1.77	
	17°F	At AHRI Rated Conditions				32800	3810	2.52		@ 1470 SCFM			
	17°F	48480	6740	2.11		48000	6880	2.04		47040	6950	1.98	
	32°F	48480	5680	2.50		48000	5800	2.42		47040	5860	2.35	
	47°F	50500	4290	3.45		50000	4210	3.48		49000	4420	3.25	
	60°F	52520	4560	3.37		52000	4650	3.27		50960	4690	3.18	

NOTE: THESE ARE "MAX OUTPUT" VALUES ARE BASED ON COMPUTER SIMULATIONS

LEGEND

DB — Dry Bulb
WB — Wet Bulb
TC — Total Capacity (BtuH)
SC — Sensible Capacity (BtuH)
Input Power—(Watts)
COP—Coefficient Of Performance

Use case 3 (from NEEP database):

AHRI Certificate # 211246029

Performance Specs

Heating / Cooling	Outdoor Dry Bulb	Indoor Dry Bulb	Unit	Min	Rated	Max
Cooling	95°F	80°F	Btu/h	14,000	55,000	56,000
			kW	1.33	6.11	6.45
			COP	3.08	2.64	2.54
Cooling	82°F	80°F	Btu/h	17,800	-	59,000
			kW	1.1	-	5.27
			COP	4.74	-	3.28
Heating	47°F	70°F	Btu/h	13,400	60,000	69,000
			kW	1.12	5.08	5.99
			COP	3.51	3.46	3.38
Heating	17°F	70°F	Btu/h	17,000	41,000	57,000
			kW	1.68	4.69	7.11
			COP	2.97	2.56	2.35
Heating	5°F	70°F	Btu/h	15,100	53,500	57,600
			kW	2.11	8	8.61
			COP	2.1	1.96	1.96
Heating	-22°F	70°F	Btu/h	14,900	-	28,300
			kW	2.09	-	6.58
			COP	2.09	-	1.26

Peak Heating Hour Emissions from ASHP + Auxiliary Electric Heating Compared to a Gas Furnace

Example:

Furnace capacity	Btu/hr	60,000
Furnace efficiency	%	95
Peak heating load	Btu/hr	48,000
	kWh	14.07

		Use Case 1	Use Case 2	Use Case 3
cc-ASHP size	ton	3.5	4	5
	Btu/hr	42,000	48,000	60,000
Capacity[1]	Btu/hr	30,400	28,500	28,300
COP[2]		1.62	1.41	1.26
Backup heating (Resistance) efficiency	%	100	100	100
Heating load supplied by ASHP	Btu/hr	30,400	28,500	28,300
Electricity consumption by ASHP	kW	5.5	5.9	6.6
Electricity consumption by ASHP for one peak hour	kWh	5.5	5.9	6.6
Heating load supplied by Resistance heating	Btu/hr	17,600	19,500	19,700
Electricity power consumption by ASHP	kW	5.16	5.72	5.77
Electricity consumption by ASHP for one peak hour	kWh	5.16	5.72	5.77
Total electricity consumption	kWh	10.66	11.64	12.36
Grid marginal emissions for ASHP+ Auxilliary Electric backup	**kgCO2**	**4.49**	**4.90**	**5.21**

Furnace peak hour gas consumption	Btu/hr	50,526	50,526	50,526
	m3/hr	1.4	1.4	1.4
Emissions from a furnace	**kgCO2e**	**2.6**	**2.6**	**2.6**

Emission Factors

Power Advisory grid Marginal Emission Factor for peak Winter Months		421	g CO2e/kWh
Gas furnace emission factor		1.9	kg CO2e/m3
		175	g CO2e/kWh

Notes::

1: Values taken from J11.5. Capacity is shown at temperatures of -25oC, -26.1oC, and -30oC for Case 1, 2 and 3 respectively

2: Values taken from J11.5. COP is shown at temperatures of -25oC, -26.1oC, and -30oC for Case 1, 2 and 3 respectively

Calculation of Grid marginal Emission Factor (MEF

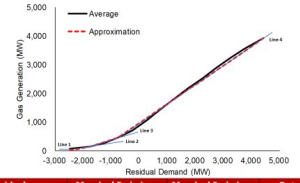
Generation Mix (MW)

Date	Hour	NUCLEAR	GAS	HYDRO	WIND	SOLAR	BIOFUEL	Total Output	Ontario Demand	Residual Demand	MEF (tonne/MWh)
2/12/2021	9	9,080	4,184	5,679	1,253	49	161	20,406	19,244	3,022	0.421

Marginal Emission Factors

Impact of Residual Demand Changes on Emissions

- The curve of Gas Generation and Residual Demand has an S-shape



- The slope of each line segment shows how Gas Generation changes in response to changes in Residual Demand

Range of Residual Demand	Marginal Emissions from Gas Generation (tonnes/MWh)	Marginal Emissions from Imports (tonnes/MWh)	Ontario MEF (tonnes/MWh)
Less than -2,500 MWh	0	0	0.00
-2,500 to -1,750 MWh	0.19 x 0.412 = 0.08	0	0.08
-1,750 to -750 MWh	0.32 x 0.412 = 0.13	0	0.13
-750 to 2,900 MWh	0.67 x 0.412 = 0.28	0	0.28
Greater than 2,900MWh	0.67 x 0.412 = 0.28	0.33 x 0.44 =0.15	0.42

- The 0.412 tonnes/MWh emission factor for gas generation is derived from total emissions divided by total output over 5 base y ears (2015 - 2019)
- Import emissions factor derived from broad view of emissions factors from imports; with import emission factors falling from an estimate of 0.58 tonnes/MWh to 0.17 tonnes/MWh by 2030 to reflect reduction in carbon intensity over time

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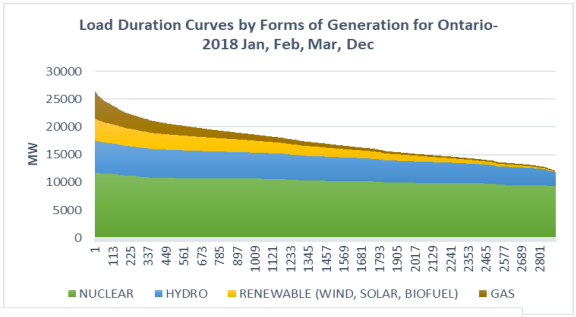
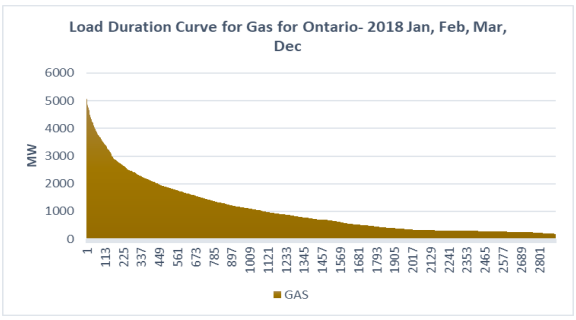
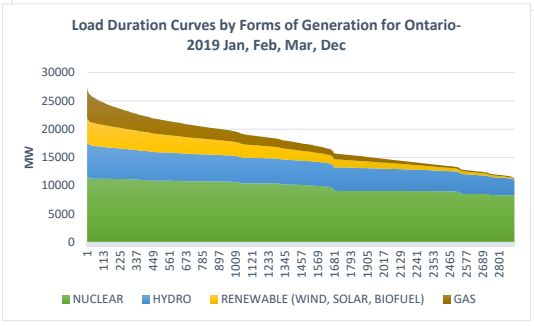
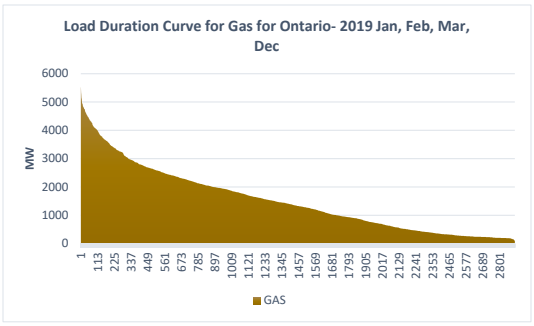
Load Duration Curves by Forms of Generation for Jan, Feb, Mar, Dec for 2018 - 2022

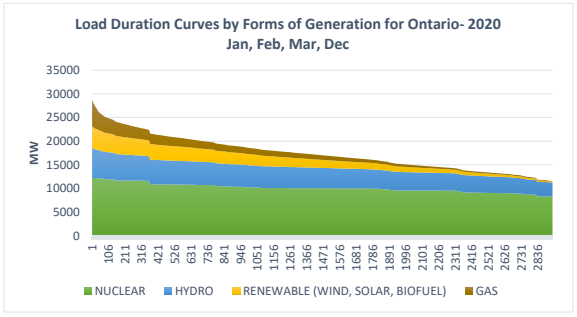
Data source: https://www.ieso.ca/en/Power-Data/Data-Directory

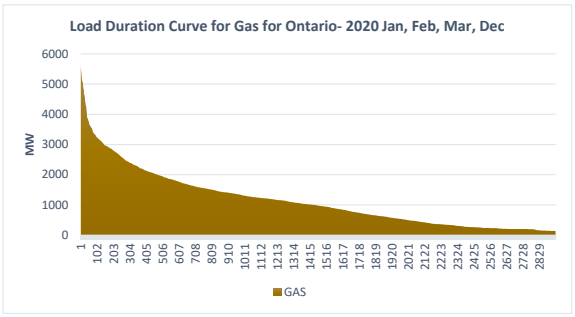


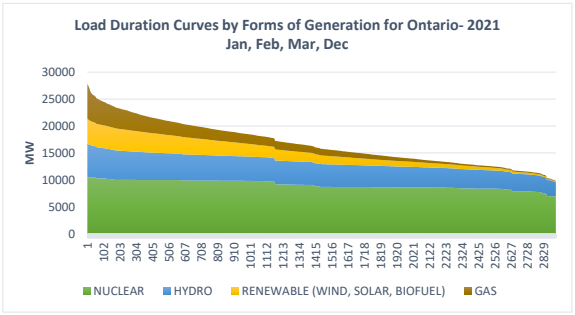


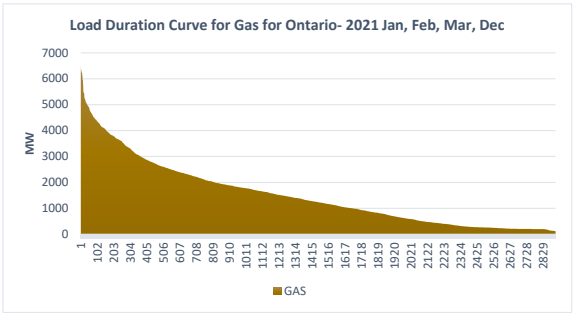


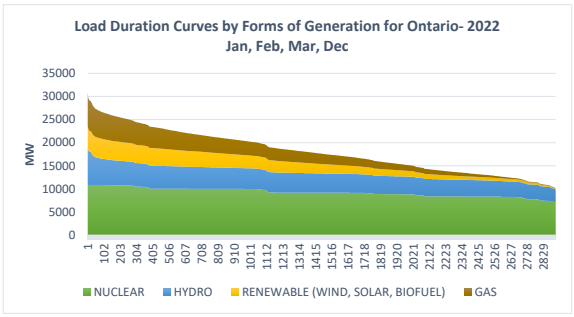


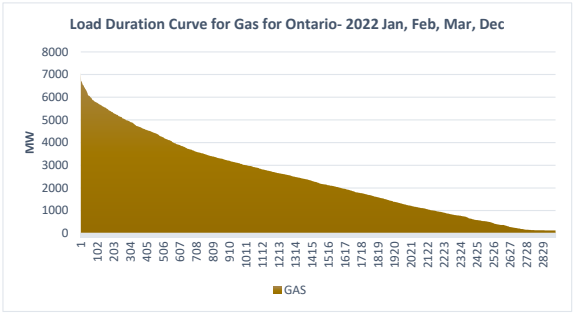












ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 118

Enbridge to update SEC 108 to include CWIPs in the year, on an annualized basis.

Response:

Please see Attachment 1 for an update to the 2023 Bridge Year in-service capital forecast by asset class including the closeout of Construction Work In Progress (CWIP) costs. Note that CWIP closeouts only impact in-service capital in 2023 and have been allocated on a best-efforts basis.

Table 1
Utility In-Service Capital Expenditures by Asset Class

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Compression Stations	EGI	11.5	40.5	51.8	62.6	362.7	43.9	53.5	17.8	26.8	18.7
2	Customer Connections	EGI	157.8	221.7	268.6	282.2	290.8	304.0	248.4	257.8	254.1	250.1
3	Distribution Pipe	EGI	209.4	127.0	387.2	505.2	272.4	350.7	356.2	299.9	250.2	316.4
4	Distribution Stations	EGI	32.8	100.2	82.7	68.4	73.2	101.2	133.6	91.4	92.6	116.7
5	Fleet & Equipment	EGI	28.8	20.3	25.3	35.1	8.9	31.5	35.4	40.1	45.7	52.3
6	Growth - Distribution System Reinforcement	EGI	134.9	77.2	49.7	90.7	50.6	75.5	219.9	34.2	56.9	12.7
7	Real Estate & Workplace Services	EGI	41.3	19.4	72.0	58.8	34.8	19.2	72.9	203.7	23.2	88.5
8	Technology Information Services (TIS)	EGI	51.6	34.0	21.5	37.7	40.3	68.9	53.4	143.1	44.9	54.1
9	Transmission Pipe and Underground Storage	EGI	10.8	42.9	95.0	57.9	42.2	52.4	174.8	177.1	292.6	130.7
10	Utilization	EGI	133.0	65.4	90.2	93.9	175.1	152.3	160.2	173.0	152.0	168.4
11	EA Fixed Overhead	EGI	25.9	27.0	19.8	28.2	25.6	39.8	40.8	41.9	43.0	23.2
12	Capitalized Overheads	EGI	180.5	200.6	-	-	-	-	-	-	-	-
13	Integration Capital	EGI	18.8	18.7	75.4	67.4	39.2	-	-	-	-	-
15	Other	EGI	15.5	30.8	11.5	4.3	7.6	52.0	61.6	28.3	28.0	36.1
16	Community Expansion	EGI	8.9	9.7	2.1	3.2	4.5	22.2	13.8	26.8	24.4	7.3
17	Union Unregulated Allocations		(3.6)	(7.2)	(12.9)	(36.2)	-	-	-	-	-	-
16	Total		1,057.8	1,028.2	1,239.9	1,359.3	1,428.1	1,313.6	1,624.7	1,535.0	1,334.4	1,275.2

Excludes in-service additions for PREP of $252M in 2024 and $6.8M in 2025.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 176

RE Exhibit No. K11.2, Page 172, Enbridge to expand explain "executing", what that means when it says "investment stage"; to expand 8 to also indicate why items indicated as "executing" may have been removed.

Response:

The Executing investment stage in Copperleaf indicates that the investment is part of the approved budget and can incur actuals in the current year.

Some investments require pre-planning and/or pre-engineering dollars in advance of finalizing the scope of work. On occasion, Enbridge Gas may initiate planning activities after an investment is created but decide not to proceed with the project for various reasons. This situation occurred with the WIND: Wheatley-1B - Panhandle Distribution Reinforcement - Wheatley Lateral Replacement and Reinforcement investment. In this case an investment was created but was subsequently cancelled prior to detailed planning activities being initiated, once customer demand was more clearly understood.

Please see Exhibit J13.13 Attachment 1 for an updated list of Appendix A investments including corrections to the AMP Planning Group descriptions and In-Service Dates.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 16

RE: VECC I.2.6-VECC-18, Enbridge to explain how it has treated the disposition of the properties noted in part (c) within rate base.

Response:

Enbridge Gas interprets the question to be speaking to parts (a) and (b) of Exhibit I.2.6-VECC-18 per TR Vol. 12 pages 15-16.

a) 3401 Schmon Parkway, Thorold. Sold. Net sale price $12,246,500.

The amounts removed from rate base are presented in Exhibit 2, Tab 2, Schedule 1, Attachment 6, updated July 6, 2023 as follows:

- Land: $1.1 million (page 1, line 2, column c)
- Building, gross cost: $15.9 million (page 1, line 5, column c)
- Building, accumulated depreciation: $6.7 million (included within page 9, line 3, sum of columns c and d)

The proceeds of sale, net of costs, were apportioned between land and building as follows:

- $4.6 million for the land and $7.6 million for the building
- The $3.5 million gain on disposition of land was recorded as Other Income[1]
- The net book value of the building at the time of sale was $9.2 million, resulting in a loss of $1.6 million. The loss on the building disposition was recorded as a reduction to accumulated depreciation.

[1] EB-2023-0092 2022 Utility Earnings and Disposition of Deferral & Variance Account Balances Application and Evidence. Please see line 11 of the table at EB-2023-0092, Exhibit B, Tab 2, Schedule 4.

b) 2023 - 335 Prichard Rd, Hamilton. Sold. Net sale price $3,033,250.

The disposition of 335 Prichard Rd was inadvertently missed in the preparation of the 2023 Bridge Year rate base forecast. The following adjustments will be reflected in rate base when drafting the final rate order.

The following amounts will be removed from rate base:

- Land: $0.3 million
- Building, gross cost: $2.4 million
- Building, accumulated depreciation: $0.7 million

The proceeds of sale, net of costs, were apportioned between land and building as follows:

- $1.0 million applicable to land and $2.0 million applicable to the building
- A $0.8 million gain on the disposition of land will be recorded in Other Income
- The net book value of the building at the time of sale was $1.6 million, resulting in a gain of $0.4 million. The gain on the building disposition will be recorded as an increase to accumulated depreciation.

After reflecting these adjustments, 2023 and 2024 rate base would decrease by $1.6 million and $2.3 million, respectively.

c) 2024 - 90 Bill Leathem Drive, Nepean, South Merivale Operation Centre (SMOC). Forecasted sale.

The amounts removed from rate base are presented in Exhibit 2, Tab 2, Schedule 1, Attachment 8, updated July 6, 2023, as follows:

- Land: $0.6 million (page 1, line 2, column e)
- Building, gross cost: $4.2 million (page 4, line 3, column e)
- Building, accumulated depreciation: $3.6 million (included within page 9, line 2, columns c and d)

The proceeds of sale, net of costs, were assumed to be the net book value of the land and building: $0.6 million for the land and $0.6 million for the building. The proceeds, represented by net book value on sale for the building, were inadvertently missed in the rate base calculation, leaving a residual value of $0.6 million in rate base. The error resulted in an overstatement of 2024 rate base of $0.2 million, which will be corrected when drafting the final rate order.

As noted in Exhibit I.2.6-VECC-18, although proceeds were estimated at $6.3 million, Enbridge Gas forecasts disposition at net book value, as gains or losses on disposition are uncertain until the time of sale after final details of the sale are known including an allocation of proceeds (net of selling and other costs) between land and building.

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 38

Enbridge to provide the project counts for the following categories and then the related capital amount per year, for the categories of mandatory compliance, value-driven, and then just the total, which should add to the 3,087 projects.

Response:

Table 1 below provides the capital costs and project counts for the mandatory, compliance and value driven categories for the data set out in the response at JT5.34. Table 2, also provided below, provides similar information however the data included in this table reflects the Capital Update filed on July 6, 2023.

Table 1
Investment Count and Total Forecast by Planning Group – Exhibit JT5.34, Attachment 1, filed April 6, 2023

Investment Category	Total Forecast ($ millions)	Investment Count
Compliance	2,957	439
Mandatory	6,340	1432
Value Driven	3,999	1216
Grand Total	**13,296**	**3087**

Table 2
Investment Count and Total Forecast by Planning Group – 2023 to 2027 from Exhibit JT5.34, Attachment 1, filed July 6, 2023, and 2028 to 2032 from Exhibit JT5.34, Attachment 1, filed April 6, 2023

Investment Category	Total Forecast ($ millions)	Investment Count
Compliance	3,056	500
Mandatory	6,559	1461
Value Driven	3,938	1285
Grand Total	**13,552**	**3246**

Note: Table 2 represents the updated Capital Evidence filed July 6, 2023. Exhibit JT5.34 showed a list of all investments from Copperleaf from 2023-2032, however the years 2028 to 2032 were not updated as part of the July 6, 2023, Capital Update filing and will be updated during Enbridge Gas's next 10-year Asset Management Plan.

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 39

Enbridge to provide a number for many projects are outside of the asset management plan in addition to the 3,087, over the rebasing period.

Response:

Please see Attachment 1 for the detailed listing of projects included within the Community Expansion and Other categories.

The total number of Community Expansion investments is 25.

The total number of 'Other' investments is 17 of which 2 are related to CNG and 15 are related to RNG.

LEG/LUG	Core/Non-Core	Regulated	Investment Code	Investment Name	Asset Class (EGI)	Asset Program (EGI)	Portfolio	Planning Group	2024F	2025F	2026F	2027F	2028F
EGD	EGD - Non-Core	CNG	48663	CNG Rental Stations -Program	Distribution Stations	DS - CNG (Non-Core)	EGD - Non-Core - Distribution Stations - CNG	TBD	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000
EGD	EGD - Non-Core	CNG	738443	CNG Customer Project #1	Distribution Stations	DS - CNG (Non-Core)	EGD - Non-Core - Distribution Stations - CNG	-	20,000,000				
EGD	EGD - Non-Core	Community Expansion	736911	Selwyn CE Services	Growth	GTH - Community Expansion (Non-Core)	EGD - Non-Core - Growth - Community Expansion - 8th Line (Selwyn Township)	TBD	192,423	76,761	63,291	32,889	33,956
EGD	EGD - Non-Core	Community Expansion	733737	Bobcaygeon	Growth	GTH - Community Expansion (Non-Core)	EGD - Non-Core - Growth - Community Expansion - Bobcaygeon	TBD	5,580,213	8,941,750	7,799,013	6,265,290	5,325,113
EGD	EGD - Non-Core	Community Expansion	734729	Chute-à-Blondeau - CE Execution	Growth	GTH - Community Expansion (Non-Core)	EGD - Non-Core - Growth - Community Expansion - Chute-à-Blondeau	TBD	-	-	2,775,827	642,575	122,548
EGD	EGD - Non-Core	Community Expansion	734725	Glendale Subdivision - CE Execution	Growth	GTH - Community Expansion (Non-Core)	EGD - Non-Core - Growth - Community Expansion - Glendale Subdivision	TBD	-	-	960,716	178,109	36,184
EGD	EGD - Non-Core	Community Expansion	734737	Humber Station - CE Execution	Growth	GTH - Community Expansion (Non-Core)	EGD - Non-Core - Growth - Community Expansion - Humber Station	TBD	-	-	-	1,385,772	54,427
EGD	EGD - Non-Core	Community Expansion	734730	Lanark and Balderson - CE Execution	Growth	GTH - Community Expansion (Non-Core)	EGD - Non-Core - Growth - Community Expansion - Lanark and Balderson	TBD	-	-	-	4,456,998	183,897
EGD	EGD - Non-Core	Community Expansion	734728	Merrickville-Wolford - CE Execution	Growth	GTH - Community Expansion (Non-Core)	EGD - Non-Core - Growth - Community Expansion - Merrickville-Wolford	TBD	-	1,154,952	152,489	56,472	22,415
EGD	EGD - Non-Core	Community Expansion	734019	East Gwillimbury CE Execution	Growth	GTH - Community Expansion (Non-Core)	EGD - Non-Core - Growth - Community Expansion - North and East (East Gwillimbury)	TBD	-	-	4,749,376	819,228	180,853
EGD	EGD - Non-Core	Community Expansion	734720	Sandford - CE execution	Growth	GTH - Community Expansion (Non-Core)	EGD - Non-Core - Growth - Community Expansion - Sandford	TBD	1,429,996	290,669	107,129	69,134	52,301
EGD	EGD - Non-Core	Community Expansion	733812	CE - Stanley's Olde Maple Farm Lane	Growth	GTH - Community Expansion (Non-Core)	EGD - Non-Core - Growth - Community Expansion - Stanley's Old Maple Lane Farm	TBD	14,473	7,353	-	-	
EGD	EGD - Non-Core	Community Expansion	735751	Eganville - CE Execution - Services	Growth	GTH - Community Expansion (Non-Core)	EGD - Non-Core - Growth - Community Expansion - Eganville	-		6,474,290	1,459,198	545,856	315,878
UG	UG - Non-Core	Community Expansion	734711	Boblo Island - CE Exectution	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Boblo Island	TBD	373,323	154,418	104,602	53,143	52,301
UG	UG - Non-Core	Community Expansion	736697	Brunner CE - Services	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Brunner	TBD	59,367	40,469	20,173	8,199	-
UG	UG - Non-Core	Community Expansion	736705	Burk's Falls CE - Services	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Burk's Falls	TBD	36,184	22,060	14,943	7,592	7,714
UG	UG - Non-Core	Community Expansion	734247	Cedar Springs CE Execution	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Cedar Springs	TBD	-	-	425,830	208,002	30,490
UG	UG - Non-Core	Community Expansion	734734	Cherry Valley CE Execution	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Cherry Valley	TBD	1,796,492	356,215	182,386	85,190	83,840
UG	UG - Non-Core	Community Expansion	737056	Haldimand Shores CE Services	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Haldimand Shores	TBD	14,398	66,813	46,769	33,406	45,551
UG	UG - Non-Core	Community Expansion	734195	Hidden Valley CE Execution	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Hidden Valley	TBD	170,929	65,130	58,826	37,358	53,143
UG	UG - Non-Core	Community Expansion	733961	Kenora District - Hwy 594 CE	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Kenora District	TBD	28,488	14,473	14,706	7,472	7,714
UG	UG - Non-Core	Community Expansion	734731	Mohawks of the Bay of Quinte FN CE Execution	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Mohawks on the Bay of Quinte FN	TBD	233,629	130,261	70,223	71,354	30,368
UG	UG - Non-Core	Community Expansion	734736	Neustadt CE Execution	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Neustadt	TBD	1,272,594	501,015	194,204	100,133	83,840
UG	UG - Non-Core	Community Expansion	734738	Red Rock - CE Execution	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Red Rock First Nation (Lake Helen Reserve)	TBD	-	-	-	332,703	57,382
UG	UG - Non-Core	Community Expansion	734739	St Charles - CE Execution	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - St. Charles	TBD	-	1,281,978	370,689	182,386	110,607
UG	UG - Non-Core	Community Expansion	734733	Tweed CE Execution	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Tweed	TBD	-	-	923,997	157,851	29,413
UG	UG - Non-Core	Community Expansion	734726	Washago - CE Execution	Growth	GTH - Community Expansion (Non-Core)	UG - Non-Core - Growth - Community Expansion - Washago	TBD	-	-	-	5,741,621	423,598
EGD	EGD - Non-Core	RNG - Regulated	738850	Project Creek	Distribution Stations	DS - RNG (Non-Core)	EGD - Non-Core - Distribution Stations - RNG	TBD	24,000,000	4,800,000	300,000	-	-
EGD	EGD - Non-Core	RNG - Regulated	102057	RNG Injection Station - Disco	Distribution Stations	DS - RNG (Non-Core)	EGD - Non-Core - Distribution Stations - RNG	TBD	393,256	-	-	-	-
EGD	EGD - Non-Core	RNG - Regulated	503454	Injection Stations - In Development	Distribution Stations	DS - RNG (Non-Core)	EGD - Non-Core - Distribution Stations - RNG	TBD	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000
EGD	EGD - Non-Core	RNG - Regulated	101964	RNG Injection Station -Evergreen Environmental (Oshawa)	Distribution Stations	DS - RNG (Non-Core)	EGD - Non-Core - Distribution Stations - RNG	TBD	4,500,000	-	-	-	-
EGD	EGD - Non-Core	RNG - Regulated	22866	Petawawa Renewables Power Corp RNG (Dundalk)	Distribution Stations	DS - RNG (Non-Core)	EGD - Non-Core - Distribution Stations - RNG	TBD	2,349,784	-	-	-	-
EGD	EGD - Non-Core	RNG - Regulated	739572	Project Niagara	Distribution Stations	DS - RNG (Non-Core)	EGD - Non-Core - Distribution Stations - RNG	-	450,000	2,250,000			
EGD	UG - Non-Core	RNG - Regulated	102360	Project Lane	Distribution Stations	DS - RNG (Non-Core)	EGD - Non-Core - Distribution Stations - RNG	-	15,400,000				
UG	UG - Non-Core	RNG - Regulated	739568	Project Essex	Distribution Stations	DS - RNG (Non-Core)	UG - Non-Core - Distribution Stations - RNG	TBD	1,435,000	8,840,000	-	-	-
UG	UG - Non-Core	RNG - Regulated	736339	RNG Injection Station and Pipeline - Ridge Landfill	Distribution Stations	DS - RNG (Non-Core)	UG - Non-Core - Distribution Stations - RNG	TBD	170,000	-	-	-	-
UG	UG - Non-Core	RNG - Regulated	736474	Watford Pipeline (RNG)	Distribution Stations	DS - RNG (Non-Core)	UG - Non-Core - Distribution Stations - RNG	TBD	14,660,000	-	-	-	-
UG	UG - Non-Core	RNG - Regulated	102494	Project London	Distribution Stations	DS - RNG (Non-Core)	UG - Non-Core - Distribution Stations - RNG	TBD	6,700,000	-	-	-	-
UG	UG - Non-Core	RNG - Regulated	737279	Seacliff	Distribution Stations	DS - RNG (Non-Core)	UG - Non-Core - Distribution Stations - RNG	-	1,600,000				
UG	UG - Non-Core	RNG - Regulated	736397	Greenfield Global	Distribution Stations	DS - RNG (Non-Core)	UG - Non-Core - Distribution Stations - RNG	-	2,800,000				
UG	UG - Non-Core	RNG - Regulated	735696	Injection Station Development	Distribution Stations	DS - RNG (Non-Core)	UG - Non-Core - Distribution Stations - RNG	-	9,000,000	9,000,000	9,000,000	9,000,000	16,000,000
UG	UG - Non-Core	RNG - Regulated	739489	Project NE	Distribution Stations	DS - RNG (Non-Core)	UG - Non-Core - Distribution Stations - RNG	-	2,114,970				
									135,775,518	**63,468,607**	**48,794,388**	**49,478,735**	**42,343,532**

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 44

RE pollution probe compendium 1, page 203, the IRP decision, to comment on Enbridge's interpretation of asset management plan.

Response:

The OEB's IRP Decision and Order[1] states on page 42: "The OEB directs that the AMP include information about Enbridge Gas's system needs."

Enbridge Gas's Asset Management Plan (AMP) describes asset management activities related to core utility assets within the company's regulated operations. The AMP is optimized to ensure effective allocation of the approved capital envelope dollars. Non-core Community Expansion[2], RNG[3] and CNG[4] projects have a separate rate recovery mechanism and, therefore, do not go through the AMP optimization process.[5] [6] As such, these non-core investments are not included within the AMP.

Although these non-core investments are not included as projects within the AMP provided at Exhibit 2, Tab 6, Schedule 2, Enbridge Gas notes:

- For Community Expansion projects, a list of the major Community Expansion projects can be found in Exhibit 2, Tab 6, Schedule 2, Section 5.1.9.3. There is also a list of projects publicly available on Enbridge Gas's community expansion website to provide information on the project status. The website is updated when additional information on the project details or project status is available. This occurs more frequently than updates to the AMP and, as such, provides the greatest level of public visibility to these projects. https://www.enbridgegas.com/en/residential/new-customers/community-expansion.

[1] EB-2020-0091
[2] Community Expansion projects receive funding from the Government of Ontario under the Natural Gas Expansion Program (NGEP).
[3] RNG Projects are funded through Enbridge's M13 Rate Schedule
[4] CNG projects are funded by customers
[5] Exhibit 2, Tab 5, Schedule 2, Page 2
[6] Tr. Vol 12 39

- For non-core RNG and CNG investments, most of these projects are subject to confidentiality agreements between Enbridge Gas and its proponents. These projects are not firm until the contract has been signed and there would be no visibility or certainty as to which projects will come to fruition until the contract is signed. Thus, there is no further visibility that can be provided through the AMP.

It should be noted that these non-core capital investments mentioned fail the IRP Binary Screening, as they are either policy driven (Community Expansion) or Customer Driven (RNG and CNG) investments.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 57

As part of the answer to J12.1, Enbridge will advise as to the amount removed from rate base for each of the properties disposed of, including the portion of that amount relevant to land and the portion relevant to buildings.

Response:

Please see the response to Exhibit J12.1.

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 68

To provide written comments that Enbridge gas has received from participants at the regional meetings for IRP, (including via the website.)

Response:

Parry Sound Pilot Area Project Feedback:

Below are the feedback and comments received to date from both the IRP pilot public open house and the regional webinar. Please note that where the source is noted as "Open House", the associated questions were received and answered in person.

The information can be found online under the Parry Sound Pilot specific web page:

https://www.enbridgegas.com/-/media/Extranet-Pages/Sustainability/regional-planning-and-engagement/parry-sound-project/230339_IRP_Parry-Sound-Pilot-Project-Feedback.ashx?rev=5613df7cebbe417d8beea42509a76f9a&hash=2F5164710DD08BB7AFE55CF9BE0B09FF

Parry Sound Pilot Project Feedback

Received on	Source	Feedback	Enbridge Gas response
May 5, 2023	Online feedback form	Many of the Municipalities and First Nations in the region are members of a formal regional climate action and energy management partnership known as ICECAP (Integrated Community Energy & Climate Action Plans). Many of these communities (including the Town of Parry Sound) are in the	We look forward to working with your organization and the communities it serves.

Received on	Source	Feedback	Enbridge Gas response
		process of developing community and corporate climate/energy plans which are in alignment with this pilot project. The Georgian Bay Biosphere (our organization) facilitates this partnership.	
May 5, 2023	Online feedback form	Bring natural gas down Rankin Lake Road past the Cn bridge. There are approximately 50 customers on propane now that would gladly switch.	Thank you for your feedback, we will pass this information along to our Community Expansion team
May 9, 2023	Online feedback form	“Low income jobs in area, mostly service-type jobs at $15-$20 an hour means that many homes have adult children and sometimes grandchildren living in sometimes small accommodations. Please consider that usage impacts these families tremendously. We use more water, more sewage, and more garbage bags than a family of two, but it is overall better for the environment to be cohabitated. We have the super, super rich here and the super poor. Please consider the poor when impacting our country values of freedom and use in our town. It’s ours. Not the cottagers. We are the workers, not them. We need less cost and flat-fees mean freedom as well as the ability to cohabitate. We moved here to get away from constricting city values. This is a remote community, not a city. It is a town of 7000 people with an hour to the next city. Understand that housing costs are driving workers away. additional costs	Enbridge offers distinct Energy efficiency programming for our low-income customers to help support customers in reducing energy costs and managing their natural gas bills.

Received on	Source	Feedback	Enbridge Gas response
		to usage. That's why we are living together, to save costs."	
May 10, 2023	Open house	Georgian Bay Biosphere – represent 8 municipalities within the region. Discussion centered around current suite of DSM programs as well as renewable initiatives and IRP.	We look forward to working with your organization and the communities it serves.
May 10, 2023	Open house	Are there capacity issues for the Enbridge system in our region?	Enbridge has identified an upcoming system constraint in Parry Sound. Enbridge is exploring various system reinforcement options as well as alternatives to support the growth and forecasted customer demands in the area and will continue to ensure that system needs are safely and reliably met.

Received on	Source	Feedback	Enbridge Gas response
May 10, 2023	Open house	How does Enbridge track potential developments and infrastructure need in a community? How would they find out if there are capacity issues? And who would they reach out to at Enbridge?	Enbridge Gas uses an economic and evaluation forecast to anticipate future customer additions. Multiple factors are incorporated into the demand forecast, including; input from Enbridge Gas regional offices and districts, municipal zone plans, developer plans, energy transition assumptions (i.e., low carbon trends), municipal GHG (greenhouse gas) targets and plans and declining average Use per customer assumptions. This information may be adjusted to reflect locally known developments and timing through our regional offices, and/or feedback received through our IRP stakeholder activities and included as part of EGI's Asset Management Plan (AMP).

Received on	Source	Feedback	Enbridge Gas response
May 10, 2023	Open house	Do the plans prepared by the municipality get shared with Enbridge and/if so, how are they incorporated?	Available municipal and developer plans, in combination with other factors such as operational input, economic factors, and energy transition assumptions, form the key inputs in forecasting the future load on the system. Models are run with the above inputs and reinforcement projects (i.e. growth projects) are identified where system constraints appear. Annual simulation and verification of the models are run to ensure they are reliable in estimating general demand on the system. The results of the future forecast are documented, and reinforcement projects are included in the EGI Asset Management Plan.
May 10, 2023	Open house	Does IRP mean that Enbridge won't be investing in new infrastructure in our communities?	Enbridge will continue to invest in our communities and IRP efforts will help ensure we are looking at the most cost-effective alternatives.
May 10, 2023	Open house	Rates have been increasing for NG, will IRP efforts impact my rates?	IRP efforts are designed to solve capacity issues in the most cost- effective way, including measures that can help customers with their energy efficiency
May 10, 2023	Open house	Will Enbridge still be connecting homes that want to switch from oil or propane?	Enbridge will continue to connect new customers and communities.

Received on	Source	Feedback	Enbridge Gas response
May 10, 2023	Open house	When will you be detailing the offers associated with IRP?	Pending OEB approval, we expect to have more program information in late 2023/early 2024.
May 10, 2023	Open house	What is Enbridge offering to the customer for participation in IRP programs?	Enbridge plans to offer enhanced incentives on a portion of our existing Energy efficiency offers.

Southern Lake Huron Pilot Area Project Feedback:
Below are the feedback and comments received to date from both the IRP pilot public open house and the regional webinar. Please note that where the Source is noted as "Open House", the associated questions were received and answered in person.

For Southern Lake Huron Pilot Project area, the information can be found online under the Southern Lake Huron Pilot specific web page:

https://www.enbridgegas.com/-/media/Extranet-Pages/Sustainability/regional-planning-and-engagement/Southern-Lake-Huron-Project/230339_IRP_Southern-Lake-Huron-Pilot-Project-Feedback.ashx?rev=cf24c8c197974e86b10ce120d928fb28&hash=AB7E879541FB7A375F522654481F5F66

Southern Lake Huron Pilot Project Feedback

Received on	Source	Feedback	Enbridge Gas response
May 16, 2023	Online feedback form	Do not touch my energy to help large cities.	Thank you for your feedback, please refer to our pilot pages for more information on how the pilot will affect your community.
May 17, 2023	Open house	Do we have programs targeting agriculture customers (i.e. chicken coop)?	Enbridge has a range of energy efficiency programs that are available to agriculture customers.
May 17, 2023	Open house	Asked about the Enbridge project (Dawn to Corunna) in Sarnia region and how this project ties in with that.	These projects are unrelated.

Received on	Source	Feedback	Enbridge Gas response
May 17, 2023	Open house	Asked clarifying questions regarding IRP, the scope of the pilot and then specifics of the ETEE/DR program for the pilots (i.e. what kind of measures, timelines etc.)	Check out our website for more information on the IRP pilots.
May 17, 2023	Open house	Does IRP mean that Enbridge won't be investing in new infrastructure in our communities?	Enbridge will continue to invest in our communities and IRP efforts will help ensure we are looking at the most cost-effective alternatives.
May 17, 2023	Open house	Rates have been increasing for NG, will IRP efforts impact my rates?	IRP efforts explore the most cost-effective alternatives that can help address system capacity constraints, where some alternatives may include energy efficiency programs that can lead to reduction in consumption and potentially lower energy bills.
May 17, 2023	Open house	When will you be detailing the offers associated with IRP?	Pending OEB approval, we expect to have more program information in late 2023/ early 2024.

General Feedback

Below is the feedback and comments received in response to our email requesting feedback post our General Regional webinars as well as the "Have Your Say" submission channel that customers can use on the IRP website. The questions and comments received via these channels (1) where relevant will be posted within the applicable specific regional webpage or (2) will inform the evolution of our Frequently Asked Questions section within the IRP website.

The frequently asked questions sections can be found on the landing page of the regional planning web page:

https://www.enbridgegas.com/sustainability/regional-planning-engagement

General Feedback

Received on	Region	Source	Feedback	Enbridge Gas response
April 6 2023	N/A	Have your say form	200 Acre Industrial Park/Highway Commercial Development	Thank you for your feedback, new developments are taken into consideration when planning our distribution systems. The information that you have indicated is important as Enbridge Gas wants to know more about energy planning and customer energy demand at regional and local levels to support short and long-term system planning. IRP is meant to run alongside our traditional customer connection and community expansion efforts as we work with policy-makers and a range of stakeholders to map out Ontario's energy future.
April 6 2023	N/A	Have your say form	New developments	Thank you for your feedback, new developments are taken into consideration when planning our distribution systems.
April 10 2023	Southeast	Webinar feedback	With safety and the environment constantly under scrutiny in this industry, are there any new industry safety protocols /	Enbridge Gas follows the existing processes as set out in the OEB's Environmental Guidelines for the Location, Construction and Operation of

Received on	Region	Source	Feedback	Enbridge Gas response
			procedures being implemented to ensure environmental safety?	Hydrocarbon Pipelines and Facilities in Ontario
April 6 2023	Southwest	Webinar feedback	New developments	Thank you for your feedback, new developments are taken into consideration when planning our distribution systems.
April 6 2023	Southeast	Webinar feedback	I urge you to recognize that the most pressing issue of our time, in Ontario, in Canada and around the world, is Biodiversity Loss and Climate Change. I am asking that you keep this front of mind when developing energy expansion plans anywhere in Ontario. If we, as a civilization do not get Biodiversity Loss and Climate Change adequately addressed in the coming years, nothing else matters! Focusing on energy affordability and reliability with predetermined gas-centric solutions, without considering the much more important impacts to Climate Change is	Thank you for your feedback we have forwarded your comments to our Energy Transition group for consideration in the demand forecast process. The integrated resource planning process allows Enbridge Gas to manage uncertainty in the path towards energy transition by potentially deferring new pipeline infrastructure with alternative solutions. Most alternatives have a lower carbon footprint which aligns with and supports municipal GHG reduction targets. IRP projects can also help to advance lower carbon fuels and technologies to the market, contributing to the pace of energy transition, cost-effectively.

Received on	Region	Source	Feedback	Enbridge Gas response
			pointless and will keep us on the path of a non-livable future. As you know, the vast majority of Canada's climate pollution comes from the extraction, transport, processing, and burning of oil (gasoline) and methane (so-called natural gas). While Ontario may not be a fossil fuel producing region, we can definitely do something to minimize the burning of methane (so-called natural gas) in buildings and oil (gasoline) in vehicles. I do not believe that your "pathway to net zero" is a legitimate plan to mitigate climate change. The latest IPCC report clearly states that the top 5 "must do" actions in order to combat climate change are to quickly and aggressively deploy wind and solar, increase energy efficiencies, stop	

Received on	Region	Source	Feedback	Enbridge Gas response
			deforestation and reduce methane emissions. When evaluating the two alternatives for the Ontario energy sector your evaluation criteria for the various solutions should be weighted, with solutions reducing GHG emissions (50% by 2030 and 100% by 2040) heavily favoured over all other criteria. The so-called 'net-zero' objective is a fool's game – Just a delay tactic used by companies who refuse to acknowledge the damage they're doing to the environment and economy. If Enbridge is seriously looking to mitigate climate change, then simply focus on reducing emissions – period. The "diversified pathway" is simply a plan to fail to significantly reduce emissions, delaying the inevitable, which is Canada's need to stop burning fossil	

Received on	Region	Source	Feedback	Enbridge Gas response
			fuels! The Electrification pathway is the only path to success, and should be aggressively pursued! The slower Canada transitions to green energy, the more opportunity costs we incur. We are way behind the rest of the world in manufacturing and deploying real clean energy solutions, hence Canadian companies are losing out. The Guidehouse study is a joke. Filled with cherry-picked data and self-fulfilling prophecies. First of all, methane (so-called natural gas) is NOT clean energy - The impact on our greenhouse gas problem is huge! I would love to see the costing models used in this study, specifically the true cost of extracting, processing, and transporting (long haul and local delivery) methane, factoring in all the government	

Received on	Region	Source	Feedback	Enbridge Gas response
			(taxpayer) subsidies. Multiple studies have clearly demonstrated that renewable energy is cheaper than burning methane in the long run. Reliability is a nonissue with renewables when they include storage solutions. The Resiliency comment is horrendous, considering that Enbridge is partly responsible for causing extreme weather events in Ontario, in Canada, and around the world! The hybrid home heating system is the worst idea ever – more blatant delay tactics to unnecessarily continue burning fossil fuels. Unlike EVs' range limitations, there is NO need for hybrid heating. Heat pumps (for space and water) are available today and work well in Ontario's climate. Maintaining multiple heating systems will	

Received on	Region	Source	Feedback	Enbridge Gas response
			cost more in maintenance than simply replacing the furnace, water heater and AC unit with a single heat pump system! As for Carbon Capture, it too is a bad joke. After more than 20 years of trying, the technology is too expensive and inefficient – Essentially, it doesn't work as advertised. Carbon Capture should only be considered in limited rare cases when renewables can't satisfy some extreme needs of certain industries. Blue hydrogen is a non-starter – it does not reduce emissions, with or without magical CCUS technology. Nothing but Green hydrogen should be considered, although it is not a good source of energy for heating buildings anyways when compared to the low cost and short deployment times of solar, wind and geothermal sources.	

Received on	Region	Source	Feedback	Enbridge Gas response
			RNG is interesting - Perhaps there's a future for this as an LNG source for remote/emergency use. The bottom line is that I do not support Enbridge laying one more single kilometre of pipe as we cannot afford to continue using methane for new growth - Electric heat pumps can provide all the building/water heat required for new residential and commercial growth. This is non-negotiable! A responsible Enbridge Plan should be to focus on turning-down existing gas services across Ontario by retrofitting existing homes, ripping out gas furnaces and water heaters, replacing them with heat pumps, within the next 20 years in line with additional renewable power sources that can be brought online in Ontario's grid.	

Received on	Region	Source	Feedback	Enbridge Gas response
			Remember - If we do not mitigate climate change by reducing emissions (50% by 2030, 100% by 2040) ASAP - Nothing else matters! If you really care about local communities, then you can also branch out into new businesses like re-wilding - restoring the natural areas that you have helped destroy. As for your stranded assets – I'm sure your accountants can find some creative ways to write them off.	
April 13 2023	GTA East	Webinar feedback	Durham Community Energy Plan, Corporate Climate Change Action Plan. Continued investigation of RNG procurement and/or self-production for use	Thank you for your feedback we have forwarded your comments to our Energy Transition group for consideration in the demand forecast process. The integrated resource planning process allows Enbridge Gas to manage uncertainty in the path towards energy transition by potentially deferring new pipeline infrastructure with alternative solutions. Most alternatives have a lower carbon footprint which aligns with and

Received on	Region	Source	Feedback	Enbridge Gas response
				supports municipal GHG reduction targets. IRP projects can also help to advance lower carbon fuels and technologies to the market, contributing to the pace of energy transition, cost-effectively.
April 13 2023	GTA East	Webinar feedback	Thank you for the seminar, but how do you address questions in regards to level of service with regard to NEW gas installations and lack of communication from Enbridge?	Thank you for your comment, customer attachment processes and wait times can be discussed with our Customer connections contact center 1-866-772-1045 (Monday to Friday from 8:30 a.m. to 5:00 p.m. EST)
April 18 2023	Toronto	Webinar feedback	There is a large scale proposed development called the Golden Mile. The City of Toronto is currently going through the EA process for the next year. This is located at Victoria Park & Eglinton in Toronto. A second large scale development in Toronto is in the Port Lands area at Cherry St & Commissioners St. Roadwork is currently underway, and the City will be accepting development	Thank you for your feedback, new developments are taken into consideration when planning our distribution systems. The information that you have indicated is important as Enbridge Gas wants to know more about energy planning and customer energy demand at regional and local levels to support short and long-term system planning. IRP is meant to run alongside our traditional customer connection and community expansion efforts as we work with policy-makers and a range of stakeholders to

Received on	Region	Source	Feedback	Enbridge Gas response
			applications starting in 2024. Future load in this area is not confirmed at this point, but a large number of mixed use buildings will be build in this area.	map out Ontario's energy future.
May 4 2023	GTA West	Webinar feedback	The Town has a Low Carbon Transition Strategy as part of our response to Council's Climate Emergency Declaration, this calls for us to achieve net zero carbon by 2030 or as soon as possible. This target is not compatible with the expansion of natural gas infrastructure in Halton Hills.	Thank you for your feedback we have forwarded your comments to our Energy Transition group for consideration in the demand forecast process. Regional plans will explore both demand-side alternative solutions and supply-side alternative solutions to meet customer demand. Demand side: Geotargeted energy efficiency programs; Demand response programs (i.e., adaptive thermostats); Supply side: Upstream deliveries; Compressed natural gas; Renewable natural gas; Liquified natural gas. In some cases, alternatives may be used in the short term, acting as a “bridge” until a long-term solution can be implemented. For example, Enbridge Gas may offer CNG in the short term until an energy efficiency

Received on	Region	Source	Feedback	Enbridge Gas response
				program can be offered in the community and enough gas savings are achieved to defer the system needs.
May 4 2023	GTA West	Webinar feedback	Seemed somewhat dismissive of renewable energy and other low carbon technologies while relying on ccs, hydrogen, and RNG as the preferred pathway, when these seem much less proven and reliable than the alternatives.	Thank you for your feedback we have forwarded your comments to our Energy Transition group for consideration in the demand forecast process. Regional plans will explore both demand-side alternative solutions and supply-side alternative solutions to meet customer demand. Demand side: Geotargeted energy efficiency programs; Demand response programs (i.e., adaptive thermostats); Supply side: Upstream deliveries; Compressed natural gas; Renewable natural gas; Liquified natural gas In some cases, alternatives may be used in the short term, acting as a “bridge” until a long-term solution can be implemented. For example, Enbridge Gas may offer CNG in the short term until an energy efficiency program can be offered in the community and enough gas savings are

Received on	Region	Source	Feedback	Enbridge Gas response
				achieved to defer the system needs.
May 4 2023	GTA West	Webinar feedback	Resilient Caledon Community Climate Change Action Plan	Thank you for your feedback we have forwarded your comments to our Energy Transition group for consideration in the demand forecast process. Regional plans will explore both demand-side alternative solutions and supply-side alternative solutions to meet customer demand. Demand side: Geotargeted energy efficiency programs; Demand response programs (i.e., adaptive thermostats); Supply side: Upstream deliveries; Compressed natural gas; Renewable natural gas; Liquified natural gas In some cases, alternatives may be used in the short term, acting as a “bridge” until a long-term solution can be implemented. For example, Enbridge Gas may offer CNG in the short term until an energy efficiency program can be offered in the community and enough gas savings are

Received on	Region	Source	Feedback	Enbridge Gas response
				achieved to defer the system needs.
May 4 2023	GTA West	Webinar feedback	There could have been more time spent on the planning process and specifics.	Thank you for your feedback. Enbridge Gas wants to know more about energy planning and customer energy demand at regional and local levels to support short and long-term system planning. We will be providing additional information on planning processes and specific alternatives being considered in our fall regional meetings.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 8

To advise as to whether Enbridge Gas would consider applying the same levellized treatment to the St. Laurent project as is proposed for the PREP project.

Response:

Enbridge Gas did not consider applying the same levelized treatment to St. Laurent as is proposed for Panhandle Regional Expansion Project (PREP) due to differences in both the materiality and scope of the projects. The forecasted in-service capital for PREP in 2024 is $252 million compared to $76 million for the 2024 segments of St. Laurent. There is also a significant difference in the revenue requirement between the projects with PREP at a sufficiency of $14 million as compared to a $2 million sufficiency for St. Laurent. Finally, as noted by Ms. Dreveny at Tr. Vol. 13 14 the St. Laurent project is a more typical project Enbridge Gas would undertake year over year in the sense that St. Laurent is an integrity driven replacement project vs a significant growth demand driven project like PREP.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 16

To consider whether there are any other mechanisms, such as variance accounts, that could address that issue of projects that don't proceed and how to make adjustments to reflect that in rates.

Response:

The issue of capital projects that do not proceed and their impact on rate base and rates is only relevant in a cost of service or test year rate setting process and not in a price cap rate setting process when prices and costs are decoupled with appropriate ratepayer protection built into the price cap mechanism. In any event, the price cap mechanism is to be decided in Phase 2 of this proceeding.

Enbridge Gas does not believe it is appropriate to address a change to in service capital relative to the requested capital envelope through a variance account for the 2024 Test Year for the following reasons:

a) Enbridge Gas understands (and the Company requests) that the OEB will be approving a capital budget envelope, rather than a line-item budget that is tied to specific projects. In some cases, there will be new priorities and cost pressures that will take the place of currently forecast projects that do not proceed. The Company's Test Year capital budget has been thoroughly tested in this proceeding. Only the projects that do proceed will be included in rate base at the next Rebasing. Parties can argue about the prudence of such projects at that time.

b) The ratemaking implications of the largest projects to be implemented in 2023 and 2024 (Dawn to Corunna and PREP) will be determined by a subsequent regulatory process, Phase 2 for Dawn to Corunna and the LTC for PREP.

c) The Company's customer connections growth capital in 2024 will be impacted by any changes to the revenue horizon under E.B.O. 188 in this proceeding and in any event, there is minimal impact on rates from capital expenditure in the in-service year, due to tax benefits.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 20

To estimate the portion of the difference between the forecast costs and the forecast revenues for 2021, 2022 and 2023 that relate to infill customers versus new connections or new developments.

Response:

Enbridge Gas is unable to determine the difference in forecast cost and revenues and therefore the shortfall in revenues attributable to infill customers. To meet this request the Company would need to retroactively assess the feasibility of approximately 4,000 individual infill account and approximately 1,000 new development projects to determine the specific forecast economics, which would be a considerable effort.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 22

To confirm whether the column titled "PV of Cash Inflows" includes the forecast revenues received from customers, as well as actual revenues received from customers in the subsequent years shown in the table.

Response:

For the historic period from 2013 to 2022, the column “PV of Cash Inflows” includes the actual revenue in the relevant year that is calculated based on the actual customers, actual rates and the actual average use in that year. The same revenue is then used and held constant for the remainder of the 40-year revenue horizon.

For the 2023 Bridge Year, revenues are calculated based on 2023 forecast of customers, rates and average use and are held constant with 2023 throughout the 40-year revenue horizon. For the 2024 Test Year, revenues are calculated based on 2024 forecast of customers. Rates and average use are held constant with 2024 throughout the 40-year revenue horizon per the OEB’s E.B.O 188 Guidelines, Appendix B.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 23

To provide a table reconciling customer connection figures between page 9 and page 10 for 2024 to 2028.

Response:

The table below provides a reconciliation of the customer connection figures shown on pages 9 and 10 of Exhibit K10.3.

Table 2.5.1
Capital Expenditures - 2023 to 2032: Gas Infrastructure - Growth - Customer Connections Breakdown

Investment Sub-Category ($ millions)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gas Infrastructure - Growth - Customer Connections	325.0	333.6	285.9	296.7	294.8	269.6	261.3	261.6	254.5	243.0
Customer Connections	286.3	304.0	248.4	257.8	254.1	250.1	242.8	246.7	240.2	229.6
Distribution Stations - Growth	0.1	1.9	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utilization - Meters Growth	18.0	16.5	17.0	18.5	19.2	12.2	11.8	11.8	11.3	10.6
Community Expansion	20.6	11.2	19.6	20.5	21.5	7.3	6.7	3.1	3.0	2.9
Total	325.0	333.6	285.9	296.7	294.8	269.6	261.3	261.6	254.5	243.0

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 25

To provide a breakdown for 2024 through 2028 of the amounts in Table 1 from the Panel 10 presentation by plant account, and also will indicate the depreciation associated with each, or the depreciation period associated with each.

Response:

Please see Table 1 for a breakdown of the 2024 forecasted customer connections spend of $304.1 million allocated by plant account. The percentage allocation by plant account would apply to each revenue horizon scenario and is applied to each subsequent year of forecasted capital expenditures for budgeting purposes.

Table 1
Allocation of Customer Connections Expenditures to Plant Accounts

Line No.	Plant Account	Plant Account Name	$ million Per Plant Account	Allocation % to Plant Account	Depreciation Rate	Depreciation Period
			(a)	(b)	(c)	(d)
1	473.01	SERVICES - METAL	17.8	6%	4.43%	40
2	473.02	SERVICES - PLASTIC	172.0	57%	2.73%	55
3	474	REGULATORS	11.4	4%	8.86%	25
4	477.01	CUSTOMER M&R EQUIPMENT	3.5	1%	3.34%	35
5	475.3	MAINS - PLASTIC	54.1	18%	2.72%	60
6	475.21	MAINS - COATED & WRAPPED	19.9	7%	3.38%	55
7	477	MEASURING AND REGULATING EQUIPMENT	15.7	5%	2.89%	40
8	478	METERS	9.7	3%	10.25%	15
9	Total Customer Connections - 2024 Forecast		304.1	100%		

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 27

To update the table to include meters and any other capital connection costs not currently included.

Response:

Please see Table 1, which has been updated to include meters and other costs associated with new customer connections. Table 1 also includes corrections to the 25-year and 30-year scenarios noted in the updated response to Exhibit J10.11.

Table 1
Customer Connections Capital Expenditure Plus Other related Costs Supported by Different Revenue Horizons

Revenue Horizons	2024	2025	2026	2027	2028	Total	Reduction vs 40-Year Revenue Horizon	CIAC per Customer
(Years)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	
40	359	304	316	315	286	1,579		
30	284	283	298	302	289	1,456	123	637
25	265	264	278	282	271	1,361	218	1,131
15	201	201	212	215	195	1,024	554	2,875
10	144	144	153	156	132	729	850	4,409

Notes:
1. 40-year revenue horizon reflects the Company's Capital Update in Exhibit 2, Tab 5, Schedule 4 filed on June 16, 2023
2. Table 1 includes the following costs associated with new customer connections:
   a) Direct capital cost
   b) Capitalized overheads
   c) Meter costs
   d) Fixed EA overheads

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 30

To provide the average cost to connect a residential customer for the latest year available broken down by direct connection costs, indirect overheads, and indicate the amount of normalized reinforcement indicated for a typical customer in the feasibility determination for that customer.

Response:

The average cost to connect a typical EGD rate zone residential customer broken down by cost categories is provided in Table 1. These figures are based on the 2024 Test Year budget.

Table 1
Cost to Average Connect a Residential Customer (EGD Rate Zone)

Direct Capital Cost	$4,105
Meter	$307
Extended Alliance Overhead	$405
Capitalized Overhead	$1,174
Average Cost of a Residential Customer (2024 budget)	$5,991
Normalized System Reinforcement Cost (NSRC)	$635

Please note that the NSRC of $635 is separately set out from the average cost of connection above, since the NSRC is applied only in assessing the economic feasibility of a customer connection.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 34

To advise how much of the $15.5 million could be saved if the study was focused on use of hydrogen in high concentrations, up to a hundred percent for industrial and other hard-to-decarbonize sectors.

Response:

As part of the system wide engineering assessment, all network asset types will be assessed for hydrogen suitability at any level including up to 100% hydrogen. That is, the study focuses on asset types rather than customer types. An expected deliverable from the engineering assessment will be identification of portions of the network that will be ready or will require retrofits to accept hydrogen blends of up to 100% hydrogen.

The implementation plan for this study may prioritize industrial customers as an initial phase. However, since there is significant uncertainty surrounding the pace and scale of the build out required for the electricity system to support large levels of electrification in Ontario, Enbridge Gas must take a holistic approach in conducting the engineering assessment of the entire natural gas network. This is necessary to ensure that the Company can optimize all hydrogen opportunities and options available to decarbonize its system. This approach supports Ontario's Hydrogen Strategy, Canada's Hydrogen Strategy, and the Canada Energy Regulator's *Canada's Energy Future 2023* report as a means of decarbonization.

Should this system wide study be eligible for any government program funding, those amounts will be credited against this estimated cost.[1]

[1] Exhibit 4, Tab 2, Schedule 6, p.18.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 35

To advise whether Enbridge is open to involving stakeholders in the development of the questions posed and answered in the study process.

Response:

Enbridge Gas does not intend to involve stakeholders in the development of questions posed or answers in this engineering assessment. The structure of the engineering assessment will follow CSA Z662 Oil and Gas Pipeline Systems code requirements. In CSA Z662, Clause 3.4 *Engineering Assessments*, it states, "the goal of engineering assessments is to provide conclusions and recommendations developed in a consistent manner with the appropriate degree of rigour" and that "the result shall be used to support decisions under an operating company's safety and loss management system".[1]

Enbridge Gas is committed to performing our due diligence to comply with code requirements and will provide visibility to the engineering assessment report to the OEB and stakeholders by making available, for viewing only purposes, "an interim and a final report…this two-stage reporting process will enable transparency and keep the OEB, and all other stakeholders informed as the study progresses" as stated in Exhibit 4, Tab 2, Schedule 6, page 18.

[1] CSA Z662:2023 Oil and gas pipeline systems, is available for purchase through the Canadian Standards Association: https://www.csagroup.org/store/product/CSA%20Z662:23/

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking

Tr: 45

Undertaking to provide investment summary reports for the new projects over $10 million included within the capital update

Response:

Please find the updated investment summary reports, originally provided in Exhibit 2, Tab 6, Schedule 2, Appendix A at Attachment 1.

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	10088	**2023**	**10**
	Investment Name		
	NPS 20 Lake Shore Replacement (Cherry to Bathurst)		

Investment Description

Issue/Concern:
General Concerns:
Vintage steel mains have shown signs of declining health due to the cumulative effects of poorly manufactured coatings, construction practices, latent third-party damages to pipe coatings and the effect of stray currents from transit infrastructure (such as the subway and streetcars). The current failure projection model forecasts an exponential increase in the number of corrosion-related failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:
- Compression couplings
- Shallow blow-off valve assemblies that could be damaged during excavation activities
- Reduction in the original depth of cover
- Continuous exposure to road salt and seasonal ground movement on bridge crossing assets
- Lack of cathodic protection on pipe casings that could result in corrosion and lead to the loss of containment
- Manufacturing defects on seam welds and fittings that could result in leaks due to prolonged stress and corrosion
- Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, resulting in accelerated corrosion and potentially loss of containment
Site-specific Concerns:
The NPS 20 Lake Shore Replacement project from Cherry Street to Bathurst Street addresses vintage steel mains installed in 1954. This project was assessed using Asset Health Review methodology, the C55 value framework, tacit knowledge from internal stakeholders and in-line inspection (ILI)/Integrity dig results. In addition to the declining health demonstrated by vintage steel mains, this pipeline is part of the KOL system in the Toronto area, known to have a number of features that make it more susceptible to accelerated degradation and/or higher risk of third-party damage. These features include but are not limited to:
- Compression couplings on mains and services
- Reduced depth of cover
- Shallow blow-off valves
- Lack of cathodic protection
- Live stubs
- Stray current from hydro infrastructure
- Possibly contaminated soils
In 2016 and 2018, inline inspections (ILI) using a robotic crawler were performed on approximately 1.9 kilometres of the 4.5 kilometres of pipe selected for Phase 1. The 2016 ILI survey found 2 areas that required immediate rehabilitation activities via 2 Integrity digs. There are an additional six Integrity digs recommended over the next 10 years. The 2018 inspection identified 24 further dig locations that would require Integrity remediation over the next 10 years as per the guidance from CSA Z662. These digs are required to mitigate the corrosion and dent features that could exhibit more than 80% wall loss or have a high probability of failure, representing significant degradation of the pipe. Costs for such Integrity digs, based on the integrity digs in 2017 and 2018, range from $350,000 to $450,000 per integrity dig. This implies that over the next 10 years EGI could be expected to spend $10,500,000 to $13,500,000 to rehabilitate these 30 locations, leaving the remaining pipe as bad as old. These Integrity digs would also require multiple construction zone impacts to the local traffic and businesses in a highly congested area of downtown Toronto. The multiple interruptions would have a negative impact to the reputation of safe and reliable service for EGI. Furthermore, the ILI survey also indicated another 10 features that may require mitigation activity within 15 years ($3.5M~$4.5M additional spend), which is an indication that the pipe is reaching the end of its safe and reliable service life and that a repair approach is not a sustainable approach.

Recommended Alternative Description

Scope of Work: This project is a size-for-size replacement of the existing NPS 20 HP steel main on Lake Shore Blvd from Cherry St. to Bathurst St.. This work includes approximately 4850 m of NPS 20 and 500 m of NPS 20 on Mill St, it runs on Lake Shore Blvd from Parliament St to Bathurst.

Resources: Construction contract in place.

Solution Impact: Main replacement project identified by Asset Management - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results. Further investigation was completed in 2018 to collect additional pipe condition data to assist in the planning, engineering and risk components. This confirmed the timing for execution of this replacement project for 2021.

Project Timing & Execution Risks: Moratoriums, third-party developments, Gardiner realignment and required easements.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
NPS 20 Lake Shore Replacement (Cherry to Bathurst)	$ 89,285,679

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 16,099,244	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 500,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value
Total Investment Cost (CA)	(15,545)
Total	**(15,545)**

ENBRIDGE **Investment Summary Report**	Investment Code **10088**	Report Start Year **2023**	Number of Years **10**
	Investment Name NPS 20 Lake Shore Replacement (Cherry to Bathurst)		

Report Generation Date: 7/20/2023

Investment Code	Report Start Year	Number of Years
10290	**2023**	**10**

Investment Summary Report

Investment Name

St. Laurent Phase 3 - Coventry/Cummings/St. Laurent (Plastic)

Investment Description

Full replacement of main comprising Network 6584 is required - the NPS 12 St. Laurent Ottawa North line is 13.3 km and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St. Laurent Control Station to Industrial Avenue as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (and does not include the crossing at the Rideau River to Station #61171A).

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion-related failures, while the C55 value framework and the 40-year risk projection are showing an increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:
- Compression couplings
- Shallow blow-off valve assemblies that could be damaged during excavation activities
- Reduction in the original depth of cover
- Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
- Lack of cathodic protection with pipe casings that could result in corrosion, causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
- Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
- Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Additional drivers from recent Integrity and Risk program are being captured and prepared as part of re-filing of LTC project.

This portion of the project is to install 800 m NPS 6, 525 m NPS 2 IP, transfer 27 services to IP from XHP, and abandon 1 station on Coventry and Cummings.

In 2018, pressure increase to Avenue O was completed. In 2019/2020, approximately 3.1 km of plastic pipe was installed on Tremblay and the Avenues and the services transferred over to IP. Due to a road moratorium, 2 km of 6-inch PE IP main on St. Laurent between Donald St. and Montreal was brought forward from 2021 to 2019/2020 and approximately 80 services.

Site-Specific Concerns: Unable to determine specific leak source due to the close proximity of the NPS 12 470 psi system. Cathodic protection was not installed until the early 1970s. Approximately 429 services are off this network.

Related Programs: 6422, 10089, 10288, 10289, 10291, 10292, 10293, 10294

Recommended Alternative Description

Scope of Work: Install 800 meters of NPS 6 and 525 meters of NPS 2 pipe, transfer 27 customers to IP. Abandon one station.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Resources: To be determined - Bid process

Timing & Execution Risks: LTC Filing being prepared for project, Regional vs. Project Execution due to resource availability

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
St. Laurent Phase 3 - Coventry/Cummings/St. Laurent (Plastic)	$ 19,985,307

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 18,255,078	$ 1,300,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 400,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Risk assessment complete - value framework to be scheduled Fall 2023

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	10293	**2023**	**10**
	Investment Name		
	St. Laurent Phase 3 - North/South (NPS12/16 Steel)		

Investment Description

Full replacement of main comprising Network 6584 is required - the NPS 12 St. Laurent Ottawa North line is 13.3 km and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St. Laurent Control Station to Industrial Avenue as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (and does not include the crossing at the Rideau River to Station #61171A).

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion-related failures, while the C55 value framework and the 40-year risk projection are showing an increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:
- Compression couplings
- Shallow blow-off valve assemblies that could be damaged during excavation activities
- Reduction in the original depth of cover
- Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
- Lack of cathodic protection with pipe casings that could result in corrosion, causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
- Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
- Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Additional drivers from recent Integrity and Risk program are being captured and prepared as part of re-filing of LTC project.
This portion of the project is replacing the main will ensure continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public. This project will install 5.3 km NPS 12 Steel Gas Main, 2.1 km NPS 16 Steel Gas Main, 5.1 km Plastic Gas Main and relay all XHP services to the new plastic gas main.

Recommended Alternative Description

To Install 2.1 km of NPS 16 XHP SC, 5.3 km of NPS 12 XHP SC and 321m of NPS 6 XHP SC.

Resources: To be determined - Bid process

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Timing & Execution Risks: The NPS 16/12 cannot be abandoned until this main is installed and all the services have been transferred onto the new IP system.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
St. Laurent Phase 3 - North/South (NPS12/16 Steel)	$ 100,695,953

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 9,500,000	$ 81,050,783	$ 4,750,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 900,000	$ 4,500,000	$ -	$ -	$ -	$ -	$ -	$ -

Risk assessment complete - value framework to be scheduled Fall 2023

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	10294	**2023**	**10**
	Investment Name		
	St. Laurent Phase 4 - East/West (NPS12 Steel)		

Investment Description

Full replacement of main comprising Network 6584 is required - the NPS 12 St. Laurent Ottawa North line is 13.3 km and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St. Laurent Control Station to Industrial Avenue as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (and does not include the crossing at the Rideau River to Station #61171A).

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion-related failures, while the C55 value framework and the 40-year risk projection are showing an increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:
- Compression couplings
- Shallow blow-off valve assemblies that could be damaged during excavation activities
- Reduction in the original depth of cover
- Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
- Lack of cathodic protection with pipe casings that could result in corrosion, causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
- Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
- Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Additional drivers from recent Integrity and Risk program are being captured and prepared as part of re-filing of LTC project.
This portion of the project is will install approx 3.2 km NPS 12 XHP Steel Gas Main and 0.6 km of 4-inch SC and abandon approx. 2.5 km of NPS 12 SC.

Recommended Alternative Description

Scope of Work: Install 3.2 km NPS 12. Also approximately 0.6 km of 4-inch SC will be installed to feed 4 stations that cannot be increased due to the age of the pipe.

Resources: To be determined - Bid process

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Timing & Execution Risks: The NPS 16/12 cannot be abandoned until this main is installed and all the services have been transferred onto the new IP system. The scope of plastic installation (Investments 10290, 10292, 10288) is still subject to change..

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
St. Laurent Phase 4 - East/West (NPS12 Steel)	$ 42,652,999

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 40,006,768	$ 2,100,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 1,630,162	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Risk assessment complete - value framework to be scheduled Fall 2023

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	11443	**2023**	**10**
	Investment Name		
	NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.		

Investment Description

Issue/Concern:

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effects of poorly manufactured coatings, construction practices, latent third-party damages to pipe coatings, and the effect of stray currents from transit infrastructure (such as the subway and streetcars). The current failure projection model forecasts an exponential increase in the number of corrosion-related failures. The C55 value framework and the 40-year risk projection show an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:
- Compression couplings
- Shallow blow-off valve assemblies that could be damaged during excavation activities
- Reduction in the original depth of cover
- Continuous exposure to road salt and seasonal ground movement on bridge-crossing assets
- Lack of cathodic protection on pipe casings that could result in corrosion and could lead to the loss of containment
- Manufacturing defects associated with seam welds and fittings that could result in a loss of containment due to prolonged stress and corrosion
- Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, resulting in accelerated corrosion and potential loss of containment.

Site-Specific Concerns: Martin Grove to St. Albans Road: Address NPS 12 pipe from Lavington Drive South to Burnhamthorpe Road, then west to Ashbourne Drive, then following Auckland Road south to St. Albans Road.

There are over 360 service connections that will be removed from the high-pressure (HP) steel main and an intermediate pressure (IP) polyethylene (PE) subsystem installed to reconnect these customers. Depth of cover (DOC) has been identified as a significant concern for these main segments as identified by 2018 and 2019 DOC surveys that found over 52% of the survey locations had DOC less than 90 cm, with 77 survey locations measuring less than 60 cm of cover. Poor DOC can lead to increased third-party damages. Additional risk factors include two unrestrained compression couplings (CCs), nine restrained CCs, and three suspect valves where, due to their installation dates, may have been tied in using unrestrained CCs (as discovered by an Integrity Assessment showing significant correlation between valves of this vintage with unrestrained CC tie-ins).

Cathodic protection history for the past 20 years shows that over 15% of the readings taken each year were below the minimum requirements. Poor cathodic protection levels can lead to corrosion.

Assets: NPS 12 pipe from Lavington Drive south to Burnhamthorpe Road, then west to Ashbourne Drive, then following Auckland Rd. South to St. Albans Road.

Related Programs: 6421, 10086.

Recommended Alternative Description

Scope of Work: Replacement of approximately 6.4 km of NPS 12 steel main from Martin Grove Road and Lavington Drive South to Burnhmthorpe Rd, then west to Ashbourne Drive, then south to Auckland Road and St. Albans Road. Approximately 360 services are to be reconnected to a new IP PE sub-system.

Resources: 2024 Out to Construction Phase 2 and resources are to be determined.

Solution Impact: Main replacement project identified by Asset Management - pipelines as high priority. Project identified due to age, pipeline condition and risk assessment results. Project will be re-evaluated as part of EDIMP program to undertake more fulsome condition assessment prior to final determination of scope.

Project Timing & Execution Risks: Moratoriums and easements.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.	$ 23,000,001

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ 2,500,000	$ 19,500,000	$ 1,000,000	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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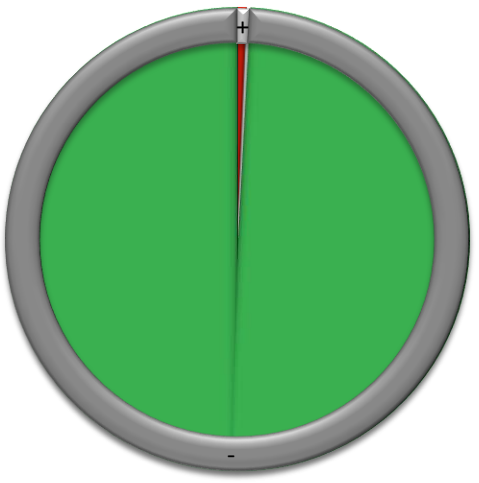
Investment Summary Report

Investment Code	Report Start Year	Number of Years
11443	**2023**	**10**

Investment Name

NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.

Alternative Value - Recommended



Value Function Measure	Value
Public Safety Risk	106
Financial Risk	31
Employee And Contractor Safety Risk	11
Reputational Risk	4
Environmental Risk And Remediation	1
Operational Risk	0
Avoided GHG Emissions (CA)	0
Budget Savings OPEX (CA)	0
Cost Avoidance CAPEX (CA)	0
Cost Avoidance OPEX (CA)	0
Total Investment Cost (CA)	(17,726)
Total	**(17,574)**

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	100295	**2023**	**10**
	Investment Name		
	Div_04: NPS 8 Port Stanley, London, Replacement		

Investment Description

Issue/Concern/Opportunity:
The NPS 8 Port Stanley line is approximately 20 km of NPS 8 built in 1959, with unknown grade and wall thickness, bare and protected, and Dresser construction (some gas welded – such welds are usually susceptible to lack of fusion imperfections). There has been a history of a significant number of leaks due to corrosion on this single-feed system that provides natural gas to Port Stanley and St. Thomas, with about 13,000 customers including the St. Thomas hospital, a psychiatric hospital in St. Thomas and a retirement home in Port Stanley.

External corrosion has created difficulties with repairs due to the inability to weld. In one repair case, it took Operations three weeks to locate a suitable weld location for a repair. Repairs often require the use of split sleeves ($8K/each). Depth of cover is a significant risk factor, with two exposed pipe sections being reported over creek crossings in December 2019. There are significant accessibility issues with locations of the pipe, making it difficult for emergency response and condition surveys. Some sections of pipe are heavily overgrown while other locations can be over 500 m from the nearest road. There are three below-grade stations that are considered confined spaces and which often flood, and must be evacuated before inspections and maintenance can occur. Gas supply from Lake Erie (New Dundee Comp) was known to have high moisture content and may contribute to internal corrosion.

No isolation is built into the single feed system; so if supply needs to be shut down, all downstream customers would be affected. In 2000, 6.8 km of main were replaced due to corrosion and exposed pipe. In 2003, 230 meters were replaced due to a Class B leak under a river crossing. Three casings on the system are known to be shorted. An attempted pressure increase in 1970 resulted in numerous leaks from compression couplings and pipe; therefore, the pipe cannot be pressure-elevated.

Assets: Port Stanley line is approximately 20 km of NPS 8 built in 1959.

Related Programs: Not applicable.

Recommended Alternative Description

Due to the condition of the existing NPS 8 ST, an approximate length of 15 km, a cost estimate has been requested for the replacement of the line. Starting at the south end at the Port Stanley Gate Station (100501) headed north approximately 2.2 km, this section can be replaced with NPS 6 ST as per System Analysis decreased from current NPS 8. A large section of NPS 8 ST (approximately 6.8 km) was replaced in 2000 and does not require replacement. Also, 3 km of NPS 8 requires replacement to NPS 6. Furthermore, 10.2 km of NPS 8 is size-for-size replacement from Middlemarch headed East to the St. Thomas South Station (110501) and from Middlemarch North to the Existing NPS 10 at Talbot Line where it connects.

Project will be re-evaluated as part of EDIMP program to undertake more fulsome condition assessment prior to final determination of scope.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name										Net Base Capex O (CA)
Div_04: NPS 8 Port Stanley, London, Replacement										$ 14,891,406
Account Type	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Base CAPEX O	$ -	$ -	$ 14,891,406	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

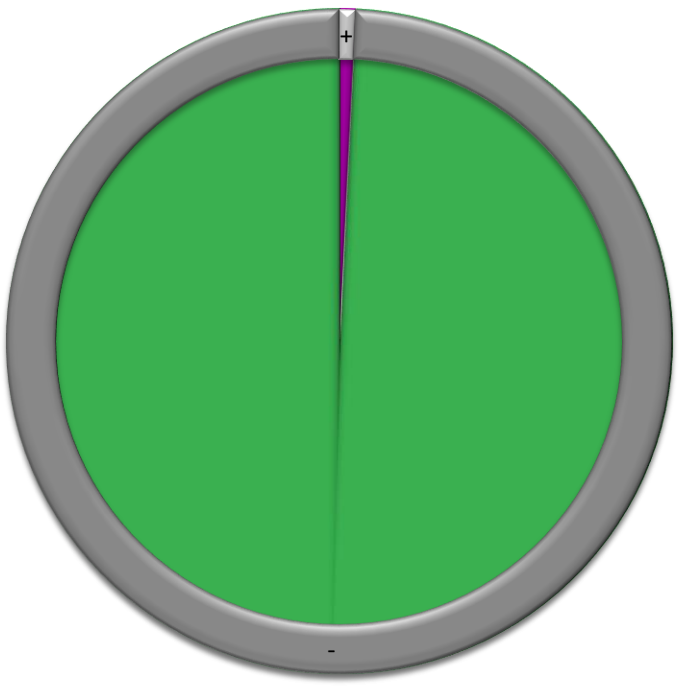
Investment Summary Report

Investment Code	Report Start Year	Number of Years
100295	**2023**	**10**

Investment Name

Div_04: NPS 8 Port Stanley, London, Replacement

Alternative Value - Recommended



Value Function Measure	Value
Financial Risk	90
Public Safety Risk	2
Reputational Risk	0
Avoided GHG Emissions (CA)	0
Budget Savings CAPEX (CA)	0
Budget Savings OPEX (CA)	0
Cost Avoidance CAPEX (CA)	0
Cost Avoidance OPEX (CA)	0
Employee And Contractor Safety Risk	0
Energy Efficiency (CA)	0
Environmental Risk And Remediation	0
Gas Storage Reliability (CA)	0
Operational Risk	0
Revenue Impact (CA)	0
Operational Disruption Risk (Gas) (CA)	0
Operational Disruption Risk (Liquids) (CA)	0
Total Investment Cost (CA)	(11,922)
Total	**(11,830)**

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	100339	**2023**	**10**
	Investment Name		
	A10: Wilson Avenue, Toronto, VSM Replacement		

Investment Description

Issue/Concern/Opportunity:
Phased replacement of NPS 12 gas main from Bathurst Ave. to Walsh Ave. Main is currently protected by Rectifier.
- The main on Wilson Ave. has numerous Pumpkins that have been installed on it. Starting from Wendell Ave. and going east towards Bathurst St.
- Corrosion on main has been an issue on Wilson Ave. due to stray current from Toronto Transit Commission (TTC) which continues to be an ongoing concern.
- The service connections have field-applied coatings which leaves a concern for future corrosion issues on this main.
- Regarding the main in the middle of the road on Wilson Ave., Curbside Valve Tee (CVT) repairs are problematic due to the location of the main.

Assets:
There is 8.5 km of NPS 12 HP Vintage Steel Main (VSM) installed between 1955 and 1964 on Wilson Ave. between Walsh Ave. and Bathurst St., Toronto.

Related Program: N/A

Recommended Alternative Description

Awaiting completion of EDIMP assessment to finalize scope. Scope, cost and schedule to be finalized upon completion of EDIMP assessment.

Scope: Replace approximately 8.5 km of 12-inch SC HP Vintage Steel Gas Main, like for like. There are approximately 384 services and 746 customers. In addition, install 2,000 m of NPS 2 PE IP and 400 m of NPS 4 PE IP, eliminating 136 HP services of the 384 existing HP services.
Resources: NPL to execute.
Solution Impact: Eliminate vintage steel main, reduce the number of HP services attached and reduce corrosion and coding deficiencies.
Project Timing & Execution Risks: 2023 to 2025
- TRCA permit is required.
- Moratorium - At Walsh Ave. W. past Matthews Gate, approximately 700 m expires December 31, 2024.
- Easement is required for the Humber River Crossing.
- Major Crossings - CP Rail, 400 Hwy, Humber River, Metrolinx – Barrie Line, the Allen, and 401 off ramp.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
A10: Wilson Avenue, Toronto, VSM Replacement	$ 82,444,743

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ 54,800,000	$ 3,000,000	$ -	$ 500,000	$ 2,000,000	$ 20,500,000	$ 1,000,000	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

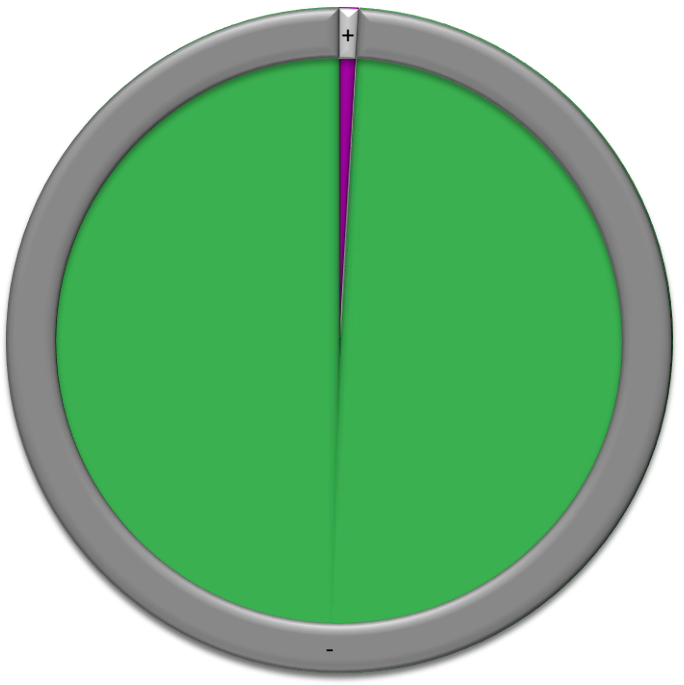
Investment Summary Report

Investment Code	Report Start Year	Number of Years
100339	**2023**	**10**

Investment Name

A10: Wilson Avenue, Toronto, VSM Replacement

Alternative Value - Recommended



Value Function Measure	Value
Financial Risk	530
Operational Disruption Risk (Gas) (CA)	39
Public Safety Risk	4
Reputational Risk	0
Avoided GHG Emissions (CA)	0
Budget Savings CAPEX (CA)	0
Budget Savings OPEX (CA)	0
Cost Avoidance CAPEX (CA)	0
Cost Avoidance OPEX (CA)	0
Employee And Contractor Safety Risk	0
Energy Efficiency (CA)	0
Environmental Risk And Remediation	0
Gas Storage Reliability (CA)	0
Operational Risk	0
Revenue Impact (CA)	0
Operational Disruption Risk (Liquids) (CA)	0
Total Investment Cost (CA)	(61,281)
Total	**(60,709)**

Report Generation Date: 7/20/2023

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
503350	**2023**	**10**

Investment Name

Moulton Replacement

Investment Description

Issue/Concern/Opportunity: 5.6 km of NPS 8 Intermediate Pressure (IP) vintage steel main to be replaced between #1472 Hwy 3 to #2199 Hwy 3 due to condition-based findings that have lowered the reliability of the pipeline. Reliability concerns include extensive historical and active leaks caused by corrosion and the presence of unconventional fittings such as below-grade threaded service tees on the line.
The pipeline is currently undergoing further integrity investigation to substantiate the need for full replacement based on ECDA, leak survey and other integrity assessments.

The in-service date (ISD) is 2025.

Justification: Replacement of NPS 8 IP vintage steel with like for like NPS 8 IP steel main for the 5.6 km segment is required to improve the reliability of the pipeline in order to mitigate risks to health, safety and reliable operation.

Assets: NPS 8 IP gas main between #1472 Hwy 3 to #2199 Hwy 3.

Related Investments: Not applicable.

Recommended Alternative Description

Replace approx. 5.6km of NPS 8 Intermediate Pressure Bare steel main with NPS 8 IP ST Yellow Jacket.

Resources: Alliance Contractor

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and the general public.

Timing & Execution Risks: MTO and other permits.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Initial		

Investment Overview

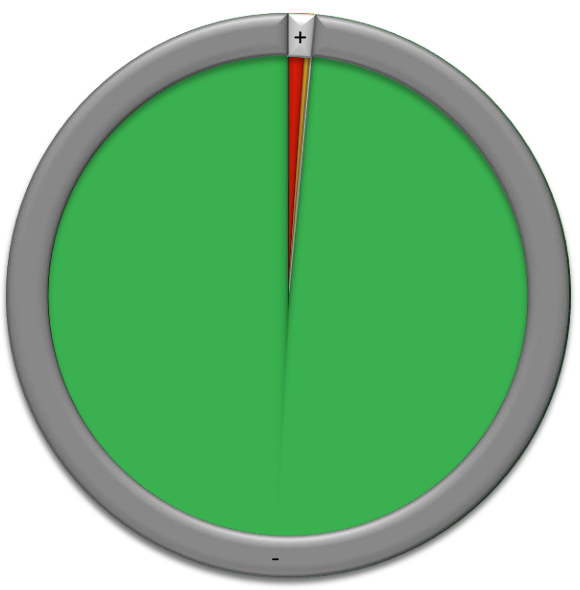
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_16 - Hamilton
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Moulton Replacement BU	$ 14,352,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 600,000	$ 13,752,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value
Public Safety Risk	124
Operational Risk	42
Employee And Contractor Safety Risk	12
Financial Risk	3
Reputational Risk	3
Environmental Risk And Remediation	1
Avoided GHG Emissions (CA)	0
Budget Savings OPEX (CA)	0
Cost Avoidance CAPEX (CA)	0
Cost Avoidance OPEX (CA)	0
Budget Savings CAPEX (CA)	0
Revenue Impact (CA)	0
Operational Disruption Risk (Gas) (CA)	0
Total Investment Cost (CA)	(11,921)
Total	**(11,735)**

Investment Summary Report	Investment Code **503350**	Report Start Year **2023**	Number of Years **10**
	Investment Name Moulton Replacement		

Report Generation Date: 2/21/2023

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
740604	**2023**	**10**

Investment Name

NPS20 KOL - Parliament St.

Investment Description

The NPS 20 assessment identifies risk results that exceeds EGI's risk threshold and supports the recommendation that this section of the pipeline (Parliament Street) requires replacement. The vintage steel replacement of the NPS 20 main on Parliament Street will help address known pipe integrity and operational field concerns by proactively replacing the steel main approaching intolerable risk due to failing pipes or pipes in poor condition. This project will replace approximately 300 m of NPS 20 HP steel main and will abandon approximately 300 m of the existing NPS 20 HP main on Parliament St. in Toronto.

Related investment: 10088

Recommended Alternative Description

Scope of Work: This project is a size-for-size replacement of the existing NPS 20 HP steel main on Lake Shore Blvd from Cherry St. to Bathurst St.. This work includes approximately 4850 m of NPS 20 and 500 m of NPS 20 on Mill St, it runs on Lake Shore Blvd from Parliament St to Bathurst.

Resources: Alliance contractor. Construction in progress.

Solution Impact: Main replacement project identified by Asset Management - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results. Further investigation was completed in 2018 to collect additional pipe condition data to assist in the planning, engineering and risk components. This confirmed the timing for execution of this replacement project for 2021.

Project Timing & Execution Risks: Moratoriums, third-party developments, Gardiner realignment and required easements.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
NPS20 KOL - Parliament St.	$ 10,117,157

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 10,117,156	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value
Total Investment Cost (CA)	(9,769)
Total	**(9,769)**

Report Generation Date: 7/20/2023

	Investment Code	Report Start Year	Number of Years
Investment Summary Report	**13034**	**2023**	**10**
	Investment Name		
	SCRW:Station-Renewal In-Place		

Investment Description

Issue/Concern: Due to the age of the facility, the compressor station experiences process safety concerns (lack of automation, unit valves, electrostatic discharge (ESD), dehydration and incinerator systems), obsolescence issues (compressor, building, electrical), code concerns (location of recycle valve/line), lack of auxiliary power, inability to support site security devices such as cameras, and setback concerns related to neighbouring occupied buildings and the nearby rail line.

Assets: Crowland Compressor Station

Justification: Modernize the facility to comply with current code and design standards.

Related Program: This project is under consideration in conjunction with an overall Crowland upgrade. Issues related to the wells and gathering system should be considered together with the compressor station's issues/concerns.

Recommended Alternative Description

Scope of Work: The compressor station will be rebuilt in place including:
- Installation of a new admin building, auxiliary building, compressor building, utilities, site safety and security system
- Decommissioning of the compressor system
- Dehydration system instrumentation and controls upgrade

Work includes full project gating cycle due to scale and complexity including stakeholder consultations, planning, detailed design, community consultations, permit applications, environmental assessments, procurement, retaining a construction contractor, isolating the system, demolition of structures/equipment to be replaced, erecting buildings, prefabricating piping, hydrotesting at shop, installing new piping and equipment, Non-Destructive Examination (NDE) as required, coating as required, inspection, training staff, energizing the system, remediating the site, and performing records updates.

Resources:
Internal Resources: Engineering, Document Control, Lands Coordinator, Reservoir Group, Instrument and Electrical, Operations, Execution, Finance, Contracts, Warehouse, Safety, EHS, and Procurement
External Resources: Engineering Firm, Site Inspector, Construction Contractor and Sub-Contractors, NDE Contractor, Survey Contractor, Concrete Testing / Ground Testing Contractor, Community Engagement, and Environmental

Solution Impact:
The new facility will be designed to current code requirements with remote operation capabilities.

Project Timing & Execution Risks:
Project timing may be revised during the Front End Engineering Design (FEED) and detailed design phases. Current approach is to minimize potential station downtime.
2023-24 - FEED, Detailed Design, Permitting, Approvals, Permitting, Procurement, Construction Ramp-up
2025 - Procurement, Prefabrication, Demolition and Construction
2026 - Restoration and Construction, Commissioning

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Distribution Stations - Gate, Feeder & A Stations
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	80 - Niagara
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	Yes

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
SCRW:Station-Renewal In-Place	$ 23,792,996

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 3,775,339	$ -	$ 17,861,007	$ 436,643	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
13034	**2023**	**10**

Investment Name

SCRW:Station-Renewal In-Place

Alternative Value - Recommended

Value Function Measure	Value
Financial Risk	662
Total Investment Cost (CA)	(19,975)
Total	**(19,313)**

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	503369	**2023**	**10**
	Investment Name		
	Lisgar Station		

Investment Description

Issue/Concern/Opportunity: The Lisgar Gate Station is located at a highly populated area in the City of Mississauga. The station is situated in an urban setting and is surrounded by residential buildings, a commercial plaza, and a church. The station has multiple feeds (two transmission lines and one XHP CER line) and various outlets to the local distribution networks. In the event of a major incident, the consequence would be significant given the close proximity to houses and buildings.

Justification: The following issues and deficiencies have been identified:
Pipes & Valves: They have been deemed unreliable at this site and require removal and installation of new pipes, fittings, and valves. The increased load demand will also allow the pipe to be upsized for current and future expansion.
Heating: The Heating system has been deemed unreliable as it has reached its end-of-life cycle usage. The placement of the heat exchangers in the basement of the Boiler building has caused maintenance roadblocks along with flooding concerns.
Pressure Regulation: The 20002A regulation has been deemed unreliable and will be rebuilt because of inconsistent flows throughout. The 20002D has suffered from frost-heaving issues as well and requires a rebuild.
Odourization: The Odourant system's current configuration does not ensure adequate containment of the odourant product in the event of a leak and does not meet the current engineering standards and approvals. The pumps need automation along with redundancy for better operational efficiency.
Building: The Regulator building that houses 20002B and 20002C needs a noise evaluation study to determine a better noise attenuation solution.
Measurement: Existing measurement is not reliable and accurate. A more robust and accurate measurement needs to be installed for custody transfer purposes.

Assets: Distribution Station Assets at the Lisgar Gate Station.

Related Program: AFF - 219 - NPS 24 Lisgar to Pine Valley - permanent launcher support (23192)

Recommended Alternative Description

Scope of Work: Rebuild the station with the following scope:
- Pipes & Valves: Replace station isolation valves with new ball valves. All station piping and valves will be examined to ensure that material specifications and their current condition are acceptable for continued use.
Projected future station capacity requirements will also be considered.
- Heating System: Replace the boilers and heat exchanger. Boiler piping will also have to be replaced to match up with the new boilers and heat exchanger. Heat exchangers will need to be replaced and installed outside of the building.
- Pressure Control: There are three different stations at Lisgar. each will be evaluated for current flow requirements through the design stage.
- Odorant System: TA new odorant building will be installed that will include sufficient secondary containment which is not part of the current design. A new odorant tank will also be required, along with a second backup pump injection system to serve as redundancy.
- Telemetry & Electrical: The existing RTU cabinet and panel will be replaced with a new Control Wave unit. The telemetry and electrical systems will be brought up to current standards and will include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry
tower upgrades, UPS installation, generator upgrades, modem and firewall upgrades, station lighting upgrades, weather station installation/replacement.
- Measurement: Four new measurement ultrasonic flowmeters will be installed on the inlet NPS 30 from the new Union Gas takeoff. Another measurement will be installed at the outlet on the NPS 24 CER line. Piping will be designed to ensure gas measurement when operationally flowing from the NPS 24CER line to the NPS 20 and reverse. The flow meters will be programmed to have automatic run switching depending on the demand. The NPS 30,20 and 16 outlets will also be equipped with annubar flow meters to capture individual flowrates leaving the station.
- Compliance & Others: Sump pumps will be replaced/relocated to remove them from the confined space.

Resources: Alliance Contractor

Solution Impact: Risk reduction to the existing Lisgar Station site by replacing obsolete equipment.

Project Timing & Execution Risks: 2023/2024 Execution

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Distribution Stations - Gate, Feeder & A Stations
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	20 - Mississauga
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Lisgar Station	$ 16,592,204

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 100,000	$ -	$ 15,782,204	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

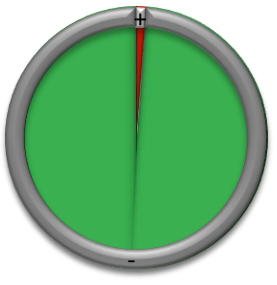
Investment Summary Report

Investment Code	Report Start Year	Number of Years
503369	**2023**	**10**

Investment Name

Lisgar Station

Alternative Value - Recommended



Value Function Measure	Value
Public Safety Risk	153
Operational Risk	4
Financial Risk	0
Reputational Risk	0
Total Investment Cost (CA)	(13,113)
Total	**(12,955)**

Report Generation Date: 7/20/2023

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
734676	**2023**	**10**

Investment Name

SARN: 13F-220R Vidal St

Investment Description

Issue/Concern/Opportunity: 13F-220R is experiencing flooding due to its current location. The heater age is of concern and the control valves require an upgrade. Potential relocation is necessary due to building floods.

Justification: Full rebuild is required.

Assets:13F-220R

Related Investments: Not applicable.

Recommended Alternative Description

Scope of Work: Full rebuild

Resources: Enbridge

Solution Impact: New Build

Project Timing & Execution Risks: Refinement of timing and execution risks will occur later in development.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Distribution Stations - Station Rebuilds & B and C Stations
Investment Stage	Long Term Planning		

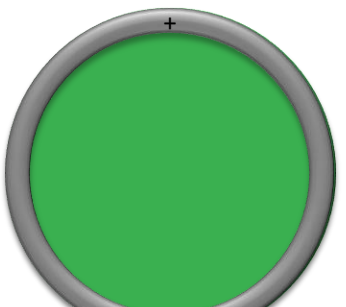
Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_03 - Sarnia
	Asset Program (EGI)	DS - Station Rebuilds & B and C Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name										Net Base Capex O (CA)
SARN: 13F-220R Vidal St										$ 12,480,001
Account Type	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,280,000	$ 11,200,000	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Assessment Scheduled Fall 2023

Value Function Measure	Value
Financial Risk	0
Employee And Contractor Safety Risk	0
Environmental Risk And Remediation	0
Public Safety Risk	0
Reputational Risk	0
Operational Risk	0
Total Investment Cost (CA)	(6,564)
Total	**(6,564)**

Report Generation Date: 7/20/2023

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
735022	**2023**	**10**

Investment Name

Sarnia Industrial Station 2029 Rebuild

Investment Description

The station is located on leased property that is limited in size and makes it difficult to install a required filter. In addition, the heater is reaching end of life and there are buried glycol lines have the potential to pose environmental risk. Egress from the site is problematic due having to cross multiple railway tracks. General concerns with equipment spacing as it pertains to ergonomics, operabilty and hazerdous area classification. There is an opportunity to merge the station with 13F-503 Churchill Rd Station.

There is a System Reinforcement project being considered if this is not proceeding the station condition concerns noted above will have to be addressed through a future scoping initiative in the next iteration of the 10Y AMP.

Recommended Alternative Description

Scope of Work: Complete rebuild of Sarnia Industrial station (like for like). This estimate provides total cost for station rebuild, high level pipeline cost for relocation within industrial park (1475 Vidal St S, Sarnia, ON N7T 7Y2) and land cost for 100*100m property.
Resources: Alliance Contractor
Solution Impact: Eliminate ergonomic and space concerns.
Project Timing & Execution Risk: TBD in next AMP

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Distribution Stations - Station Rebuilds & B and C Stations
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	DS - Station Rebuilds & B and C Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Sarnia Industrial Station 2029 Rebuild	$ 11,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ 2,000,000	$ 8,000,000	$ 1,000,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Assessment Scheduled Fall 2023

Value Function Measure	Value
Total Investment Cost (CA)	(6,746)
Total	**(6,746)**

Report Generation Date: 7/20/2023

	Investment Code	Report Start Year	Number of Years
Investment Summary Report	**1024**	**2023**	**10**
	Investment Name		
	NW 6581 Ottawa Reinforcement Phase 2 SRP		

Investment Description

Issue/Concern/Opportunity: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers. This network in Ottawa is predominantly made up of residential and commercial customers. In the current configuration, a high pressure network is exclusively fed by both the Ottawa and Richmond Gate Stations. An upstream flow constraint has been identified at the Ottawa Gate Station, along with a bottleneck constraint for gas fed from Richmond Gate Station. The South outlet of Ottawa Gate can be set to as low as 400 psig (normally 470 psig) while Richmond Gate is kept at 470 psig, thus flowing more gas from the west to the east.

The current configuration, an existing NPS 12 high pressure pipeline along Fallowfield Road is a bottleneck for gas flowing from the west to Richmond Gate Station, and to eastern areas. The previously constructed Ottawa Reinforcement Plan (ORP) Phase 1 as well as the Strandherd River crossing has helped move gas from Richmond Gate eastward to areas of concentrated and growing gas demand.

This reinforcement will assist in moving additional gas from Richmond Gate toward the areas that would be serviced by Ottawa Gate, and remove the bottleneck constraint. There were approximately 193,553 customers on the associated networks as of 2016.

Assets: Existing NPS 12 HP Pipe

Related Program: Not applicable

Recommended Alternative Description

Scope of Work: The proposed scope includes the installation of 7 km of NPS 12 high pressure main from Greenbank Rd. and W Hunt Club Rd. to Princess of Wales Dr. and W Hunt Club Rd. along W Hunt Club Rd.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Project Timing & Execution Risks: The Project is proposed to start in 2027 and be completed by 2031.

Risks: Weather impacts, resource availability, and procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
NW 6581 Ottawa Reinforcement Phase 2 SRP	$ 53,489,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ 268,000	$ 5,348,000	$ 47,070,000	$ 535,000	$ 268,000	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 7/20/2023

Investment Code	Report Start Year	Number of Years
30542	**2023**	**10**

Investment Summary Report

Investment Name

SRP_Southeast_Owen Sound_County Rd 40_Reinforcement_NPS12_11800m_4670kPa

Investment Description

Risk/Concern/Opportunity: The Owen Sound system north of St. Jacob's historically adds about 1300 customers per year and growth has been strong along the lakeshore (Port Elgin, Southampton, Owen Sound & towards Collingwood).

Assets: Loop existing 10-inch Steel 4,670 kPa main from existing PH4 reinforcement to Squire, Ontario with 12-inch steel main. Install valve site and 12-inch receiver facilities.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: The project will loop the existing NPS10 ST 4670 kPa main from existing PH4 reinforcement to Squire, Ont with NPS12 ST main. As well as install a valve site and 12" receiver facilities. Alternative running lines and pipe sizes can be determined closer to the project design stages. This project supports all pressures downstream to Owen Sound, Port Elgin, Southampton, Wiarton, Sauble Beach and east of Owen Sound, but supports growth on the entire system. Actual growth rates and loads will need to be confirmed closer to the project planning stages.

Resources: Company crews, 3rd party contractor crews and 3rd party vendors.

Solution Impact: Organic growth on the Owen Sounds system wide primarily north of St Jacobs Transmission Station. This reinforcement supports the entire system and downstream networks.

Project Timing & Execution Risks: System reinforcement is required in 2025 as per current plan and significant growth on systems. Risks include weather, resource availability, procurement of materials, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_07 - Waterloo
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
SRP_Southeast_Owen Sound_County Rd 40_Reinforcement_NPS12_11800m_4670kPa	$ 26,400,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 528,000	$ 2,112,000	$ 22,440,000	$ 1,320,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 7/20/2023

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
30579	**2023**	**10**

Investment Name

SRP_Southwest_Wonderland_New STN & MOP Upgrade

Investment Description

A Maximum Operating Pressure (MOP) upgrade of the 6,160 listed pipe out of Hensall Transmission, upgrade to the inlets of existing stations along this line to 6,160 kPa inlet MOP, and installation of new station near Lucan to regulate from 6,160 to 3,450 is required.

Recommended Alternative Description

Scope of Work: The project will increase the Operating MOP of an existing 24 km NPS 8 ST pipeline from 3,450 kPa to 6,160 kPa from the existing Hensall Transmission Station to the town of Lucan. To accommodate the MOP increase, a new station will be installed near Lucan, Ontario to regulate from the upgraded 6,160 kPa MOP system into the existing downstream 3,450 kPa MOP system. Existing distribution stations along the portion of the line to receive the operational MOP upgrade will be assessed and modified to accommodate the new inlet MOP. Alternative options to service a limited number of customers (~30) directly on the existing line can be assessed in detail closer to the project date. This project supports all pressures downstream from the Hensall Transmission Station, including into the London distribution network and north into the Forest, Hensall, Goderich areas. Actual growth rates and loads will need to be confirmed closer to the project planning stages.

Resources: Company crews, 3rd party contractor crews and 3rd party vendors.

Solution Impact: Organic growth on the London Distribution Network and north into the entire Hensall system, including but not limited to the areas of Forest, Hensall, Goderich, Grand Bend, and Stratford. This upgrade supports the entire system and downstream networks.

Project Timing & Execution Risks: System reinforcement is required in 2025 as per current plan and significant growth on systems. Risks include weather, resource availability, procurement of materials, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
SRP_Southwest_Wonderland_New STN & MOP Upgrade	$ 16,200,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ 16,200,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 7/20/2023

Investment Code	Report Start Year	Number of Years
100703	**2023**	**10**

Investment Summary Report

Investment Name

SRP_LUG East_Kingston_Creekford Rd_Reinforcement_NPS8_6200m_6895kPa

Investment Description

Issue/Concern/Opportunity: Kingston lateral replacement to be completed from Westbrook CMS to Woodbine TBS to account for forecast growth, and to address Class Location change and depth of cover issues which exist on the current Kingston lateral.
Assets: Kingston Lateral Replacement
Related Program: N/A

Recommended Alternative Description

Scope of Work: The project will replace the existing NPS 6 ST 6895 kPa distribution pipeline from the Westbrook TCPL takeoff to the Woodbine Town Border Station with an NPS 8 ST 6895 kPa pipeline. This project supports all pressures downstream to Kingston. The project is required to support growth and address additional other depth of cover, station and class location issues.

Resources: Company crews, 3rd party contractor crews and 3rd party vendors.

Solution Impact: Organic growth on the Kingston system wide. This reinforcement supports the entire system and downstream networks.

Project Timing & Execution Risks: System reinforcement is required in 2026 as per current plan and significant growth on systems. Risks include weather, resource availability, procurement of materials, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_22 - Kingston
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
SRP_LUG East_Kingston_Creekford Rd_Reinforcement_NPS8_6200m_6895kPa	$ 34,008,964

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ 8,080,768	$ 24,340,420	$ 1,587,776	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 7/20/2023

Investment Summary Report

Investment Code	Report Start Year	Number of Years
736259	**2023**	**10**

Investment Name

Hamilton Reinforcement Project

Investment Description

Issue/Concern/Opportunity :Reinforcement required to support changes to industrial demand in the area.

Assets: Distribution Reinforcement

Related Program: N/A

Recommended Alternative Description

Scope of Work:
- The preliminary preferred route consists of approximately 14 km of NPS 12 pipe.
- It begins at TCE (at a new gate station) and heads northeast and then west to the customer site.
- Install NPS 12 ST 4140 kPa MOP dedicated main to customer. Dedicated main will begin at the TCE crossing on Regional Rd 56 (43.167912, -79.784155 - A) and continue along Upper Centennial Parkway to Barton St to Kenilworth Ave to the customer site (43.258819, -79.804792 - B).
- It is a direct line from TCE feed.
- The project consists of a new gate station, a new customer station and 2 customer station rebuilds.
-The proposed facilities for the final state will also meet the transition state requirements for the customer.

Resources: Capital Development, Business Development, Engineering Construction

Solution Impact: In May 2021, the customer initiated a significant growth project with Enbridge for an increased demand of 96,000 m3/hr.

Project Timing & Execution Risk: ISD 2025

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_16 - Hamilton
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Hamilton Reinforcement Project	$ 99,208,792

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 3,000,000	$ 9,118,200	$ 81,990,592	$ 5,000,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 8/2/2023

Investment Summary Report

Investment Code	Report Start Year	Number of Years
736975	**2023**	**10**

Investment Name

Enbridge Gas Distribution System Hydrogen Feasibility Study

Investment Description

Comprehensive techno-economic feasibility study of blending hydrogen into Enbridge Gas Inc.'s (EGI) existing natural gas distribution and transmission network across Ontario.

Evaluate the technical feasibility and maximum limits of blended hydrogen gas in existing networks,identify necessary retrofits or upgrades for varying concentrations of hydrogen, and develop a staged roadmap for transitioning Ontario's gas network to a low-carbon future in line with technical and economic barriers and opportunities. The assessment comprises the entirety of EGI's gas pipeline network in Ontario.

By blending hydrogen at strategic locations across EGI's existing gas network, EGI aims to reduce the carbon intensity of its 3.8 million residential, commercial, institutional and industrial customers across over 500 communities in Ontario.

Recommended Alternative Description

Scope of Work:

Evaluate the technical feasibility and maximum limits of blended hydrogen gas in existing networks, identify necessary retrofits or upgrades for varying concentrations of hydrogen, and develop a staged roadmap for transitioning Ontario's gas network to a low-carbon future in line with technical and economic barriers and opportunities. The assessment comprises the entirety of EGI's gas pipeline network in Ontario:
- 78 214 km of gas distribution main lines
- 66 787 km of gas distribution service lines
- 5 471 km of gas transmission lines

Resources: 3rd party contractor
Solution Impact: By blending hydrogen at strategic locations across EGI's existing gas network, EGI aims to reduce the carbon intensity of its 3.8 million residential, commercial, institutional and industrial customers across over 500 communities in Ontario.

Project Timing & Execution Risks:
Study to be completed in 2026

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - Hydrogen Blending
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	GTH - Hydrogen Blending
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Enbridge Gas Distribution System Hydrogen Feasibility Study	$ 12,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 1,817,667	$ 4,500,000	$ 4,700,000	$ 900,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 8/2/2023

Investment Code	Report Start Year	Number of Years
48715	**2023**	**10**

Investment Summary Report

Investment Name

Dawn C Compression Lifecycle

Investment Description

Issue/Concern:
**** An Asset Health Review is underway and will inform a third-party Reliability, Availability and Maintainability Study to quantify risks associated with asset failures. These activities will support additional detailed alternatives analysis and final scoping which will in turn inform the project cost estimate, timing and business case.

Dawn C Plant is one of the nine centrifugal compressors located at the Dawn Compressor Station. It is primarily used to lift from lower storage pressure levels, experienced later in the operations season, to intermediate pressure levels. The intermediate pressure level is typically elevated further in pressure by another compressor to reach the desired Dawn outlet pressure. Dawn Plant C and Plant D have a suction pressure rating of 195 psig, the lowest rating of the compressor fleet at Dawn. Considering the other compressors at Dawn have a 225 psig minimum inlet rating, Dawn Plants C and D become very critical when pool storage levels fall below 225 psig, as they typically do late in the operational season. Overall, compression can pose a very large consequence of failure as compressors are integral assets required to achieve the Dawn to Parkway Transmission System deliverability requirements throughout the year.

The consequence of compressor failure is dominated by gas cost impacts to customers. Transmission system consequences associated with failure of a single compressor are heavily influenced by the time of year, weather severity and time to mitigate the failure. Siemens, the original equipment manufacturer (OEM) of the Dawn C compressor, has indicated that 40 years is the typical timeframe for supporting the supply of engine parts required to recover from a critical engine failure or to complete recommended overhauls. Dawn Plant C was installed in 1984, which indicates that the RB211- 24A engine in Plant C is reaching end of life.

Justification: By continuing to comply with OEM-recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risk is controlled to moderate levels but risk increases gradually over the 25,000-hour recommended interval between overhauls. Availability of parts is essential to repair internal engine failures and complete overhauls. Notably, the RB211-24A in Plant C has non-standard dimensions and cannot be retrofitted with more modern editions of the RB211 without significant plant retrofits. Similar to the 40-year old Dawn Plant B, which was replaced and retired in 2017 due to the risks associated with discontinued OEM support of critical engine parts, it is expected that Dawn Plant C will be exposed to a similar level of risk as the global inventory of spare components diminishes.

Assets: Dawn Plant C

Related Programs: Not applicable.

Recommended Alternative Description

Scope of Work:
Removal and abandonment of the plant, associated piping and electrical, and remediation of land back to level grade. A new compression facility and its associated infrastructure will be developed and installed at the Dawn Compressor Station.

Work includes full project gating cycle due to scale and complexity including: stakeholder consultations, planning, detailed design, permit applications, environmental assessment. procurement, retaining a construction contractor, isolate system, demolition of structures/equipment to be replaced, erect buildings if required, prefabricating piping, hydrotesting, install new piping and auxiliary systems, NDE as required, coating, inspection, train staff, energize system, remediating site, and records updates.

Resources:
Consultant resources for design
Contractor resources for abandonment, construction and commissioning
Regulatory approval

Solution Impact:
This project will ensure the safe removal of infrastructure and the replacement of 32,000 hp of obsolete compression to support the storage to transmission requirements at Dawn.

Project Timing & Execution Risk:
Regulatory approval and planning - 2 years, abandonment and remediation 18 months.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Compression Stations - Growth
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_53 - Union South Storage
	Asset Program (EGI)	CS - Growth
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48715	**2023**	**10**

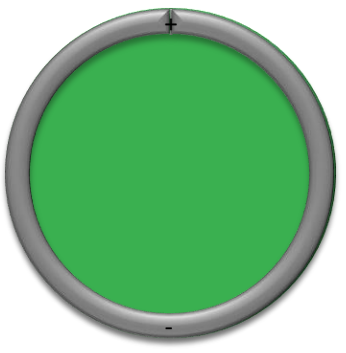
Investment Name

Dawn C Compression Lifecycle

Alternative Spend Profile - Recommended

Name									Net Base Capex O (CA)
Dawn C Compression Lifecycle									$ 125,200,000
Account Type	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Base CAPEX O	$ 200,000	$ -	$ 12,096,000	$ 24,192,000	$ 75,576,000	$ 13,096,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value
Financial Risk	287
Operational Risk	3
Employee And Contractor Safety Risk	0
Environmental Risk And Remediation	0
Public Safety Risk	0
Reputational Risk	0
Total Investment Cost (CA)	(131,866)
Total	**(131,576)**

Report Generation Date: 8/3/2023

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48732	**2023**	**10**

Investment Name

Waubuno Compression Lifecycle

Investment Description

Issue/Concern/Opportunity:
**** An Asset Health Review is underway and will inform a third-party Reliability, Availability and Maintainability Study to quantify risks associated with asset failures. These activities will support additional detailed alternatives analysis and final scoping which will in turn inform the project cost estimate, timing and business case.

The Waubuno compressor elevates available pipeline pressure to the Waubuno Pool Maximum Operating Pressure (MOP). Compression increases the working inventory value of the pool by approximately3.5 PJ on top of what the pipeline alone can achieve. The compressor is operated approximately 45 days per year in late summer to early fall to top off the pool. The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the Waubuno compressor is heavily influenced by the level of the pool at which the failure occurs and time to mitigate the failure.
The Joy Compressor (manufactured in 1985) was a used compressor package and installed at Waubuno in 1988. The Joy Compressor Company changed ownership approximately 20 years ago whereupon original equipment manufacturer (OEM) support for the compressor was discontinued. Although normal wear components are still available in the marketplace, replacement major compressor items such as cylinders, crankshafts, and rods, etc., required to support a critical failure are no longer available. In the event of a critical failure, sourcing used parts (which are rare) or aftermarket custom machining services would be the only options for repair. This was the case in 2007 when a discharge valve seat failed, resulting in catastrophic damage to cylinder 611. An extensive search across the used parts dealers was required to secure a viable used cylinder head. Other internal damage was repaired through custom machining services.

Justification: In the event of a future failure, if usable parts or custom machining are not available, the two options would be custom-designed aftermarket castings (if possible) or replacement of the entire compressor. However, both options would render the compressor out of service for at least one operational season.

Assets: Waubuno Compressor

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
In order to meet lifecycle needs for the Waubuno storage facility, Enbridge Gas Distribution and Storage (GDS) is proposing to construct a new NPS 20 pipeline from Waubuno to TR-7 (~1.6 km). This will eliminate the requirement for a remote compressor at Waubuno; and therefore, this project will also involve the abandonment of the Waubuno Remote Compressor Unit and related equipment.
Waubuno Station Modifications (common in all scenario alternatives)
- New Control and Measurement Building
- Upgrade meters, control valve, and filter/separator
- Launcher and associated piping
Pipeline Construction
- NPS 16 Pipeline from Waubuno to TR-7/TR-2/TR-1
- ~1.5 KM NPS 20 Line (1,440 psi MOP)
- Connection to TR-7 (for injection); to TR-2 (200# Storage Suction); to TR-1 (Flexibility/Optionality)
- Valving to connect new pipeline with TR-1, TR-2, and TR-7 with overpressure protection
- Receiver and associated piping at new TR-7 valve site
- New Control Building
- Waubuno Compressor Abandonment (common in all alternative scenarios)
- Removal of the compressor and any associated equipment in compressor building.
- Removal of all the NPS 8 compressor suction and discharge piping back to their take-off at the bypass control valve.
- Removal of the aftercooler, filter and silencer.
- Removal of all electrical wiring, control wiring and SCADA communication wiring and panels associated with the compressor.
- Removal of the compressor building and foundation. As the site has been in existence since the 1980s, there is a strong possibility of ground contamination that will need remediation.
Resources:
- Consultant resources for design
- Contractor resources for abandonment, construction and commissioning
Solution Impact:
Replace approximately 3.5 PJ of inventory provided by the current compressor that is obsolete and poses the risk of significant downtime in the event of a failure.
Project Timing & Execution Risks:
- Requires Ontario Energy Board Leave to Construct approval
- Pool out of service
- Pipeline route not finalized
- Landowners may want abandoned pipeline removed
- Dependent on TR-7 pipeline
- 2025 in-service date

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Compression Stations - Replacements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_53 - Union South Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48732	**2023**	**10**

Investment Name

Waubuno Compression Lifecycle

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Waubuno Compression Lifecycle	$ 23,076,900

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 252,000	$ 1,864,800	$ 20,866,860	$ 93,240	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 932,400	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value
Financial Risk	15,242
Total Investment Cost (CA)	(19,245)
Total	**(4,004)**

Report Generation Date: 8/3/2023

Investment Code	Report Start Year	Number of Years
100901	**2023**	**10**

Investment Summary Report

Investment Name

Dawn to Corunna

Investment Description

Issue/Concern/Opportunity:

EGI recognizes its obligation to meet the firm demands of its customers; and as a result, assets are continually evaluated to identify hazards and to assess risks in order to ensure that they remain reliable, suitable, and fit for continued service. To this end, an Asset Health Review (AHR) was performed in 2018 and updated in 2021 as part of EGI's comprehensive Reliability, Availability and Maintainability (RAM) Study for the Corunna Compressor Station (CCS), which was completed by a consultant. The results of this study indicate that the health and maintainability of certain compressor units at the CCS are in decline. Reasons for this decline include, but are not limited to performance, functional issues with custom components (i.e., spare parts) and wear. As a result of these assessments, EGI has identified increasing obsolescence and reliability risks associated with certain CCS compressor units and is experiencing a need for increased maintenance and repair work to keep the units operational going forward.

Further, as a result of the compressor units' obsolescence and reliability issues, EGI has experienced continued and increasing compressor unit downtime and long lead repair time. This has created a need for increased maintenance and repair work performed by EGI personnel at the CCS. EGI has also undertaken comprehensive studies, including a site-wide quantitative risk assessment (QRA) to determine the severity of the increasing safety risks, and has determined that the current configuration of compressor units (which includes multiple compressor units in close proximity within a single building) results in an excessive level of process safety risk.

Assets: Compressors K701, K702, K703, K705, K706, K707 and K708

Related Investments: 734634 - Dawn to Corunna (Dawn Tie-in)

Recommended Alternative Description

Scope of Work:
The scope of the project includes the retirement and abandonment of 7 of the 11 existing reciprocating compressor units at the Corunna Compressor Station (CCS) and the construction of approximately 20 km of NPS 36 pipeline from the Dawn Operations Centre in the Township of Dawn Euphemia to the Corunna Compressor Station in St. Clair Township. The project will also include station work at the Dawn Operations Centre and the Corunna Compressor Station required to tie in the new pipeline.

Resources:
- Consultant resources for design
- Contractor resources for abandonment, construction and commissioning

Solution Impact:
This alternative provides a one-to-one replacement in design day storage system withdrawal capacity compared to the existing compressor units at the CCS facility that are proposed to be retired and abandoned. The NPS 36 pipeline will also provide equivalent storage injection capacity via existing compression units located within Dawn. Further, the proposed pipeline simplifies EGI storage operations by reducing the amount of rotating assets and running equipment. This opportunity to replace compression with a pipeline alternative also reduces emissions through utilization of existing hp compression at Dawn which have a lower burn rate (at higher efficiency).

Project Timing & Execution Risks:
- 2021: File environmental assessment (EA) with Ontario Pipeline Coordination Committee (OPCC).
- 2022: File with Ontario Energy Board (OEB).
This project will need two years of design procurement and construction and requires EA and regulatory approval. In-service date is slated for 2023.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Replacements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	Yes
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Dawn to Corunna	$185,393,137

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 143,679,771	$ 10,811,759	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 316,000	$ 3,426,659	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

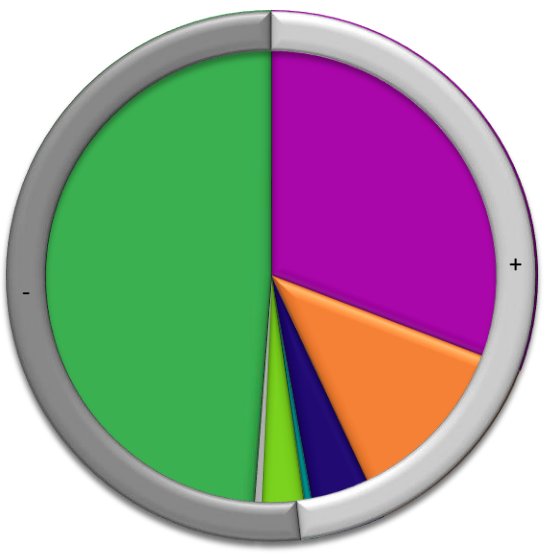
Investment Summary Report

Investment Code	Report Start Year	Number of Years
100901	**2023**	**10**

Investment Name

Dawn to Corunna

Alternative Value - Recommended



Value Function Measure	Value
Financial Risk	94,532
Cost Avoidance OPEX (CA)	37,800
Cost Avoidance CAPEX (CA)	12,499
Employee And Contractor Safety Risk	1,649
Budget Savings OPEX (CA)	(9,115)
Energy Efficiency (CA)	539
Avoided GHG Emissions (CA)	836
Environmental Risk And Remediation	0
Public Safety Risk	0
Reputational Risk	0
Budget Savings CAPEX (CA)	(145)
Revenue Impact (CA)	0
Total Investment Cost (CA)	(149,676)
Total	**(11,081)**

Report Generation Date: 8/3/2023

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
734634	**2023**	**10**

Investment Name

Dawn to Corunna (Dawn Tie-in)

Investment Description

Issue/Concern/Opportunity:
EGI recognizes its obligation to meet the firm demands of its customers; and as a result, assets are continually evaluated to identify hazards and to assess risks in order to ensure that they remain reliable, suitable, and fit for continued service. To this end, an Asset Health Review (AHR) was performed in 2018 and updated in 2021 as part of the Company's comprehensive Reliability, Availability and Maintainability (RAM) Study for the Corunna Compressor Station (CCS), which was completed by a consultant. The results of this study indicate that the health and maintainability of certain compressor units at the CCS are in decline. Reasons for this decline include, but are not limited to performance, functional issues with custom components (i.e., spare parts), and wear. As a result of these assessments, the Company has identified serious and increasing obsolescence and reliability risks associated with certain CCS compressor units and is experiencing a need for increased maintenance and repair work to keep the units operational going forward.
Further, as a result of the compressor units' obsolescence and reliability issues, the Company has experienced continued and increasing compressor unit downtime and long lead repair time. This has created a need for increased maintenance and repair work performed by EGI personnel at the CCS. EGI has also undertaken comprehensive studies, including a site-wide quantitative risk assessment (QRA) to determine the severity of the increasing safety risks, and has determined that the current configuration of compressor units (which includes multiple compressor units in close proximity within a single building), results in an excessive level of process safety risk.

Assets: Compressors K701, K702, K703, K705, K706, K707 and K708

Related Investments: 100901 - Dawn to Corunna

Recommended Alternative Description

Scope of Work:
This portion of the project is specific to the Union rate zone and the dismantlement of Tecumseh Measurement and tie-in to Dawn yard for the NPS 36 pipeline.

Overall Project Scope
The scope of the project includes the retirement and abandonment of 7 of the 11 existing reciprocating compressor units at the Corunna Compressor Station (CCS) and the construction of approximately 20 km of NPS 36 pipeline from the Dawn Operations Centre in the Township of Dawn Euphemia to the CCS in St. Clair Township. The project will also include station work at the Dawn Operations Centre and the CCS required to tie-in the new pipeline.

Resources:
- Consultant resources for design
- Contractor resources for abandonment, construction and commissioning

Solution Impact:
This alternative provides a one-to-one replacement in design day storage system withdrawal capacity compared to the existing compressor units at the CCS facility that are proposed to be retired and abandoned. The NPS 36 pipeline will also provide equivalent storage injection capacity via existing compression units located within Dawn. Further, the proposed pipeline simplifies EGI storage operations by reducing the amount of rotating assets and running equipment. This opportunity to replace compression with a pipeline alternative also reduces emissions through utilization of existing hp compression at Dawn which have a lower burn rate (at higher efficiency).

Project Timing & Execution Risks:
- 2021: File environmental assessment (EA) with Ontario Pipeline Coordination Committee (OPCC).
- 2022: File with Ontario Energy Board (OEB).
This project will need two years of design procurement and construction and requires EA and regulatory approval. In-service date is slated for 2023.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Compression Stations - Replacements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_53 - Union South Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Dawn to Corunna (Dawn Tie-in)	$ 83,312,912

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 82,034,638	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 5,794,552	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

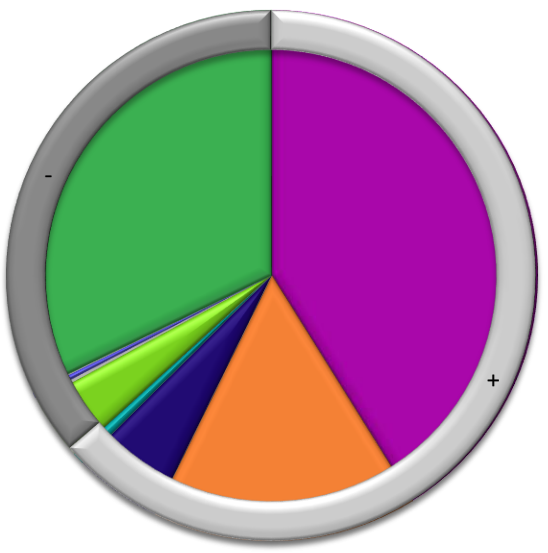
Investment Summary Report

Investment Code	Report Start Year	Number of Years
734634	**2023**	**10**

Investment Name

Dawn to Corunna (Dawn Tie-in)

Alternative Value - Recommended



Value Function Measure	Value
Financial Risk	96,546
Cost Avoidance OPEX (CA)	37,800
Cost Avoidance CAPEX (CA)	12,499
Employee And Contractor Safety Risk	1,782
Budget Savings OPEX (CA)	(9,115)
Energy Efficiency (CA)	539
Avoided GHG Emissions (CA)	836
Environmental Risk And Remediation	0
Public Safety Risk	0
Reputational Risk	0
Budget Savings CAPEX (CA)	(145)
Revenue Impact (CA)	0
Total Investment Cost (CA)	(75,480)
Total	**65,262**

Report Generation Date: 7/20/2023

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48709	**2023**	**10**

Investment Name

Hagar KVGR and Cycle Mix Cooler

Investment Description

Issue/Concern: The Hagar Liquefied Natural Gas (LNG) Plant was installed in 1968 to provide security of supply to the Sudbury industrial and distribution markets. The KVGR Compressor is one of the two compressors used to power the refrigerant process which cools the natural gas feedstock to -160°C at which point the natural gas turns into a liquid. The KVGR Compressor is necessary to produce LNG. The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the KVGR Compressor is heavily influenced by the time of year, weather severity and time to mitigate the failure. Over its 50 years of operation, the 1,500 horsepower Ingersoll Rand KVGR Compressor has amassed 140,000 operational hours. The compressor is obsolete and, although normal wear components are still available in the marketplace, some core compressor replacement items such as cylinders, crankshafts, pistons, etc., required to support a critical failure may no longer manufactured by the original equipment manufacturer (OEM). In the event of a critical failure, securing used parts (which are rare) or aftermarket custom machining services may be the only option for a timely repair. In the event custom machining services are not able to make a repair, a custom-designed aftermarket casting option or complete replacement of the compressor would be required rendering the LNG plant out of service for at least one operational season .

Assets: Compressor and Cycle Mix Cooler

Related Programs: Not applicable.

Recommended Alternative Description

Scope of Work: Replacement of the 1,500 horsepower KVGR Compressor

Solution Impact: Mitigate the risk of a critical part failure that is non-repairable due to obsolescence.

Resources: Projects will work with a third-party engineering firm to complete the design and a contractor to complete the field work. Operations will support Major Projects as required.

Project Timing & Execution Risks: The proposed timing to complete the on-site work is during the second and third quarters of the year. Design and ordering of long-lead items will need to occur a year in advance. Due to the age of the plant, the replacement of an individual component such as the compressor introduces a risk of the compatibility of new equipment with the existing balance of the plant. This could result in a change in project scope or an approach that favours broader plant renewal.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - LNG - Replacements
Investment Stage	Long Term Planning		

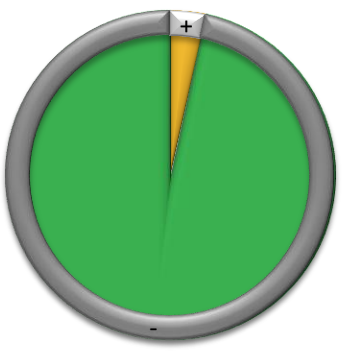
Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_92 - Union North Storage
	Asset Program (EGI)	LNG - Replacements
	Asset Class (EGI)	LNG
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name										Net Base Capex O (CA)
Hagar KVGR and Cycle Mix Cooler										$ 31,820,000
Account Type	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,500,000	$ 17,592,000
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value
Operational Risk	527
Financial Risk	2
Reputational Risk	0
Employee And Contractor Safety Risk	0
Environmental Risk And Remediation	0
Public Safety Risk	0
Total Investment Cost (CA)	(14,973)
Total	**(14,443)**

Report Generation Date: 8/3/2023

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48714	**2023**	**10**

Investment Name

Hagar Cold Box

Investment Description

Issue/Concern: The Cold Box is several heat exchangers in series used to cool the natural gas feedstock to -160°C at which point the natural gas turns into a liquid. The Cold Box is the core of the liquefied natural gas (LNG) station and is necessary to produce LNG. The consequence of a Cold Box failure is dominated by customer impact. Risk of associated failure is heavily influenced by thermal cycling and operational hours. Over its 50 years of operation, the Cold Box has amassed 140,000 operational hours. Significant failure modes include leakage of natural gas or refrigerants out of the piping into the interior of the Cold Box shell reaching potentially explosive levels or heat exchanger cross leaks that reduce the effectiveness of the refrigeration process. Both of these failure modes impair LNG production to the extent the plant cannot meet its annual production requirements. As the Cold Box internals are encased in very densely packed insulation and clad in an outer steel jacket, troubleshooting and repair of either of these failure modes is extremely difficult and time consuming.

Assets: Cold Box

Related Programs: Not applicable

Recommended Alternative Description

Scope of Work: This project involves replacement of the Cold Box.

Solution Impact: Considering the complex nature of internal repair or replacement of the Cold Box, a reactive response to internal leakage would render the liquefaction process out of production and unable to meet its regulated requirements for at least an operational season. Due to the age of the plant, the replacement of an individual component such as the Boil Off Gas (BOG) Compressor introduces a risk of the compatibility of new equipment with the existing balance of the plant. This could result in a change in project scope or an approach that favours broader plant renewal.

Resources: Projects will work with a third-party engineering firm to complete the design and a contractor to complete the field work. Operations will support Major Projects as required.

Project Timing & Execution Risks: The proposed timing to complete the on-site work is during the second and third quarters of the year. Design and ordering of long-lead items will need to occur a year in advance.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - LNG - Integrity
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_53 - Union South Storage
	Asset Program (EGI)	LNG - Integrity
	Asset Class (EGI)	LNG
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Hagar Cold Box	$ 11,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,500,000	$ 8,500,000
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value
Avoided Reactive Replacement	582
Total Investment Cost (CA)	(5,410)
Total	**(4,828)**

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	49955	**2023**	**10**
	Investment Name		
	Hagar JVG Compressor Upgrade		

Investment Description

Issue/Concern: The Boil-Off Gas (BOG) compressor is one of the two compressors used to power the refrigerant process which cools the natural gas feedstock to -160°C at which point the natural gas turns into a liquid. The BOG compressor was also used to recover BOG (i.e., natural gas vapours) from the liquefied natural gas (LNG) storage tank which occurs on a continuous basis due to the ambient warming of the tank exterior. In 2012, a separate compressor was installed to manage the LNG storage tank boil-off gas.

The BOG compressor is necessary to produce LNG. The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the BOG compressor is heavily influenced by the time of year, weather severity and time to mitigate the failure. Over its 50 years of operation, the 240 horsepower Ingersoll Rand BOG compressor has amassed 325,000 operational hours. The compressor is obsolete and, although normal wear components are still available in the marketplace, some core compressor replacement parts such as cylinders, crankshafts, pistons, etc., required to support a critical failure may no longer manufactured by the original equipment manufacturer(OEM). In the event of a critical failure, securing used parts (which are rare) or aftermarket custom machining services are the only options for a timely repair. This was the case in 2017 when an aftermarket service was solicited to develop a weld and machine repair of a compressor cylinder which had failed. The aftermarket service was able to design a custom repair which took three months to complete. In the event that the cylinder is not repairable, a custom-designed aftermarket casting or a complete replacement of the compressor may be options. These options would take the plant out of service for at least one operational season.

Assets: BOG compressor

Related Programs: Not applicable

Recommended Alternative Description

Scope of Work: Replacement of the 240 horsepower Boil Off Gas (BOG) Compressor (JVG)

Solution Impact: Mitigate the risk of a critical part failure that is non-repairable due to obsolescence.

Resources: Projects will work with a third-party engineering firm to complete the design and a contractor to complete the field work. Operations will support Major Projects as required.

Project Timing & Execution Risks: The proposed timing is to complete the on-site work during the second and third quarters. Design and ordering of long-lead items will need to occur a year in advance.
Due to the age of the plant, the replacement of an individual component such as the BOG compressor introduces a risk of the compatibility of new equipment with the existing balance of the plant. This could result in a change in project scope or an approach that favours broader plant renewal.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - LNG - Replacements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_92 - Union North Storage
	Asset Program (EGI)	LNG - Replacements
	Asset Class (EGI)	LNG
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Hagar JVG Compressor Upgrade	$ 26,820,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,500,000	$ 14,592,000
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

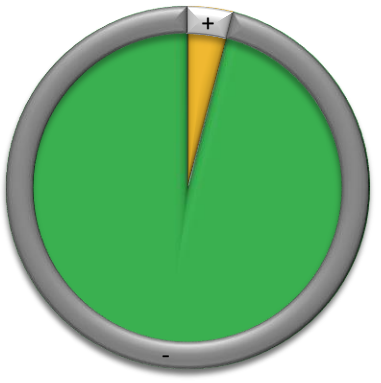
Investment Summary Report

Investment Code	Report Start Year	Number of Years
49955	**2023**	**10**

Investment Name

Hagar JVG Compressor Upgrade

Alternative Value - Recommended



Value Function Measure	Value
Operational Risk	527
Financial Risk	2
Reputational Risk	0
Employee And Contractor Safety Risk	0
Environmental Risk And Remediation	0
Public Safety Risk	0
Avoided Reactive Replacement	0
Total Investment Cost (CA)	(12,629)
Total	**(12,100)**

Report Generation Date: 8/3/2023

Investment Code	Report Start Year	Number of Years
48654	**2023**	**10**

Investment Summary Report

Investment Name

Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)

Investment Description

Issue/Concern: In response to increased natural gas demand growth along the Dawn Parkway System, the Kirkwall to Hamilton Expansion will provide reliable, secure, economic natural gas capacity to meet the growing design day demand of the Dawn Parkway Transmission system which serves both in- and ex-franchise markets.

Assets:

The Kirkwall-Hamilton Expansion Project consists of 10.2 km of NPS 48 pipeline from the Kirkwall Valve Site to the Hamilton Valve Site.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
System installation of approximately 10.2 km of NPS 48 internally-coated pipeline from Kirkwall Valve Site (17V-302) to Hamilton Valve Site (18W-601V) on the Dawn Parkway System.

Resources:
Projects group to provide project management support from design and planning phase to project execution.

Solution Impact:
Capacity is available on the Dawn Parkway System to meet in-franchise growth and customer demand.

Project Timing & Execution Risks:

As of Spring 2023, project ISD timing is projected to be in 2027.

In March 2021, this project was pushed out to 2025 and is forecast for November 1, 2026 in-service date. This project was filed with the Ontario Energy Board (OEB); but due to the global pandemic, there was demand uncertainty and the project ultimately was paused. Transmission System Planning will indicate when this project needs to move forward. Further analysis will need to be done based on the OEB decision regarding Integrated Resource Planning (IRP). With any project involving a pipeline, there will be land acquisition risk, opposition risk and the risk of a positive decision by the OEB.

Schedule delays due to right-of-way access for survey, environmental studies, permitting, and/or issuance of OEB Leave to Construct may put at risk the planned in-service date.

Proposal is based on Class 4 level cost estimates. There is risk that actual capital costs could exceed the estimate.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_16 - Hamilton
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)	$188,274,584

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$1,000,000	$18,000,000	$38,247,415	$115,027,169	$16,000,000	$0	$0	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 8/1/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	49758	**2023**	**10**
	Investment Name		
	Panhandle Regional Expansion Project		

Investment Description

Issue/Concern:
For additional details and justification, refer to the Panhandle Regional Expansion Project (PREP) Leave to Construct applicatio EB-2022-0157. To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System:

Assets:
i. Dawn Yard: ((Now Moved to INV 740055)) 700 m of 8960 kPa MOP NPS42 station header is required to maintain the maximum sustainable pressure on design day. This header will also provide operational flexibility and security of supply to the Panhandle system.
ii. Panhandle Take-off Station: The existing station will be modified to meet the new system capacity demand requiring measurement, odourization and regulation assets.
iii. Dover Transmission Station: This existing regulating station will be modified to connect the new NPS 36 pipeline to the upstream system. Flow measurement equipment will also be added to the station.
iv. Panhandle Loop : 19 km of 6040 kPag MOP NPS36 pipeline will parallel the NPS 20 from Dover Transmission station to a new valve site at Richardson Sideroad.
v. Richardson Sideroad Valve Site: A new valve site is required at the end of the NPS 36 Panhandle loop to connect to the existing NPS20 mainline. Isolation valves and launcher/receiver facilities will be installed at this location.

Related Program:
Not applicable

Recommended Alternative Description

1. Scope:

To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System:

2. Resources:
This project will be internally managed by EGI staff. Construction work, such as well drilling and new pool piping installation, will be performed by contractors.

3. Solution Impact:
Expansion of the Panhandle system provides customers with increased access to diversity, reliability and security of supply of the Dawn Hub.

4. Project Timing & Execution Risks:
This project starts 2021 with its feasibility endorsed in Q2 2022. Construction will commence in 2024. The expected in-service date is Fall 2024

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_02 - Chatham
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Panhandle Regional Expansion Project	$202,993,529

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$17,600,000	$154,301,171	$5,338,837	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 8/1/2023

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100086	**2023**	**10**

Investment Name

Panhandle Line Replacement

Investment Description

Issue/Concern: EGI's Integrity Management team initiated work in 2019 to better understand the risk associated with the two NPS 12 crossings that connect the Panhandle Eastern System owned and operated by Energy Transfer in Michigan with the EGI system in Ontario. These two crossings, installed in 1947, have never been internally inspected to check for the presence of the primary threat of internal corrosion; such inspection cannot be achieved given the configuration of the asset. A risk assessment was recently completed for the river crossings. The risk assocaited wtih a pipeline failure has been evaluated and exceeds upper risk tolerance, driving the need for treatment.

Assets: Transmission Pipeline (Canada Energy Regulator-regulated crossing)

Related Programs: Not applicable.

Recommended Alternative Description

Scope of Work: Replacement of the twin NPS 12 Crossings with a single pipeline of equivalent capacity.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Solution Impact: The principal risk is the lack of In-line Inspection (ILI) data needed to inform effective decision-making to mitigate a potential loss of pipeline containment (i.e., leak). Replacement with a new single pipeline, designed, manufactured and constructed to current standards that is ILI-capable can address this risk.

Project Timing & Execution Risks: Original in-service date is estimated to be Q3 2024. Overall project schedule is highly dependent on regulatory process and discussion with joint partner (Energy Transfer).

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Replacements
Investment Stage	Executing		

Investment Overview

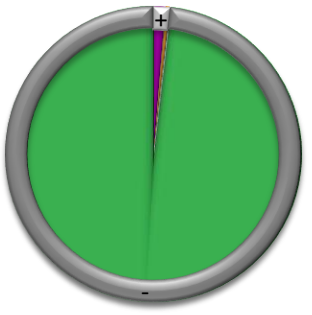
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_01 - Windsor
	Asset Program (EGI)	TPS - Replacements
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	Yes
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Panhandle Line Replacement	$ 29,770,279

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 1,119,900	$ 25,257,660	$ 3,392,719	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value
Financial Risk	305
Environmental Risk And Remediation	105
Reputational Risk	46
Operational Risk	6
Public Safety Risk	0
Total Investment Cost (CA)	(24,511)
Total	**(24,050)**

Report Generation Date: 7/20/2023

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100699	**2023**	**10**

Investment Name

Dawn Parkway Expansion Project (Dawn-Enniskillen NPS 48)

Investment Description

Issue/Concern: In response to increased natural gas demand growth along the Dawn Parkway System, the Kirkwall to Hamilton Expansion will provide reliable, secure, economic natural gas capacity to meet the growing design day demand of the Dawn Parkway Transmission system which serves both in- and ex-franchise markets.

These facilities are incremental to the Kirkwall to Hamilton Expansion (INV 48654) and timing is dependent on the Dawn Parkway System demands.

Assets:

Install approximately 17.2 km of NPS 48 internally-coated pipeline from Dawn Compressor Station (10G-301) to Enniskillen Valve Site (11H-301V) on the Dawn Parkway System.

Related Program:
Not applicable

Recommended Alternative Description

Scope of Work:
Install approximately 17.2 km of NPS 48 internally-coated pipeline from Dawn Compressor Station (10G-301) to Enniskillen Valve Site (11H-301V) on the Dawn Parkway System.

Resources:
Projects group to provide project management support from design and planning phase to project execution.

Solution Impact:
Capacity is available on the Dawn Parkway System to meet in-franchise growth and customer demand.

Project Timing & Execution Risks:
- Schedule delays due to right-of-way access for survey, environmental studies, permitting, and/or issuance of OEB Leave to Construct may put at risk the planned in-service date.

- This project will follow Kirkwall to Hamilton (48654). It will be based upon studies done by the Transmission System Planning identifying a need for expansion based upon the demands from the study.

- Further analysis will need to be done based on the OEB decision regarding Integrated Resource Planning (IRP).

- With any project involving a pipeline, there will be land acquisition risk, opposition risk and the risk of a positive decision by the OEB.
- Estimate/ Forecast does not include MOP Upgrade or Dawn Station Work.
- Current forecast in-service date of 2029 to 2030

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Dawn Parkway Expansion Project (Dawn-Enniskillen NPS 48)	$ 246,634,252

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ 24,612,151	$ 49,222,260	$ 148,187,690	$ 24,612,151	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Investment Summary Report	Investment Code **100699**	Report Start Year **2023**	Number of Years **10**
	Investment Name Dawn Parkway Expansion Project (Dawn-Enniskillen NPS 48)		

Report Generation Date: 8/1/2023

	Investment Code	Report Start Year	Number of Years
Investment Summary Report	**735972**	**2023**	**10**
	Investment Name		
	PREP: NPS 36 looping to Comber Transmission		

Investment Description

Issue/Concern:
Panhandle System expansion is driven by in-franchise growth in Chatham-Kent, Windsor-Essex and surrounding areas, including the fast-growing greenhouse market in the Leamington/Kingsville area. Based on the current forecast for in-franchise general service and contract growth in the Panhandle Transmission System market, EGI has determined that the next Panhandle facilities for expansion will need to be in place). These facilities are incremental to the Panhandle Regional Expansion Project and timing is dependent on the Panhandle System demands.

Assets:
Install approximately 12 km of NPS 36 pipeline from Richardson sideroad, looping the existing Panhandle NPS 20 pipeline to Comber Transmission Station (05E-403).

Related Program:
Not applicable

Recommended Alternative Description

Scope
To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System by installing approximately 12 km of NPS 36 pipeline from Richardson Sideroad, looping the existing Panhandle NPS 20 pipeline to Comber Transmission Station (05E-403).

Resources
This project will be internally managed by EGI staff. Construction work, such as well drilling and new pool piping installation, will be performed by contractors.

Solution Impact
Expansion of the Panhandle system will provide customers with increased access to diversity, reliability and security of supply of the Dawn Hub.

Project Timing & Execution Risks
This project starts in 2026 with its feasibility endorsed in Q2 2027.
Original forecast for construction will commence in 2028. The expected in-service date is Fall 2028.
As of Spring 2023 ISD is now closer to 2030

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_02 - Chatham
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
PREP: NPS 36 looping to Comber Transmission	$ 70,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ 7,000,000	$ 14,000,000	$ 42,000,000	$ 7,000,000	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 8/1/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	736923	**2023**	**10**
	Investment Name		
	Panhandle Regional Expansion Project - Leamington Interconnect		

Investment Description

Issue/Concern/Opportunity:
To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System,

Assets:

i) Leamington Interconnect : 12 km of 6040 kPag MOP NPS16 pipeline connecting the Leamington North Line, Leamington North Loop, Mersea Line and Kingsville East Line.
ii. Leamington Interconnect Valve Sites: Three new valve sites with isolation valves are required to connect to each of the existing laterals (1. Leamington North Line and Leamington North Loop, 2. Mersea Line and 3. Kingsville East Line). Launcher/receiver facilities will be installed at location 1 and 3.

Related Program:
Not Applicable

Recommended Alternative Description

1. Scope Install approximately 11 km of NPS 16 connecting Kingsville East Line, Mersea Line and the Leamington North Lines.

Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

2. Resources:
This project will be internally managed by EGI staff. Construction work, such as well drilling and new pool piping installation, will be performed by contractors.

3. Solution Impact:
Expansion of the Panhandle system provides customers in the Leamington and Kingsville area with increased access to diversity, reliability and security of supply of the Dawn Hub.

4. Project Timing & Execution Risks:
This project starts 2021 with its feasibility endorsed in Q2 2022. Construction will commence in 2026. The expected in-service date is Fall 2026.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_01 - Windsor
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Panhandle Regional Expansion Project - Leamington Interconnect	$ 90,509,939

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 50,000	$ 172,130	$ 21,118,437	$ 64,020,960	$ 4,946,024	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 8/1/2023

	Investment Code	Report Start Year	Number of Years
Investment Summary Report	**740055**	**2023**	**10**
	Investment Name		
	Panhandle Regional Expansion Project - Dawn Facilities		

Investment Description

Issue/Concern:
To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System:

Assets:
i. Dawn Yard (Moved to INV740055) : 700 m of 8960 kPa MOP NPS42 station header is required to maintain the maximum sustainable pressure on design day. This header will also provide operational flexibility and security of supply to the Panhandle system.

Related Program:
Not applicable

Recommended Alternative Description

1. Scope:

To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System:

i. Dawn Yard: 700 m of 8960 kPa MOP NPS42 station header is required to maintain the maximum sustainable pressure on design day. This header will also provide operational flexibility and security of supply to the Panhandle system.

2. Resources:
This project will be internally managed by EGI staff. Construction work, such as well drilling and new pool piping installation, will be performed by contractors.

3. Solution Impact:
Expansion of the Panhandle system provides customers with increased access to diversity, reliability and security of supply of the Dawn Hub.

4. Project Timing & Execution Risks:
This project starts 2021 with its feasibility endorsed in Q2 2022. Construction will commence in 2025. The expected in-service date is Fall 2025.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Panhandle Regional Expansion Project - Dawn Facilities	$ 74,074,925

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 30,200,000	$ 4,261,330	$ 37,003,886	$ 668,560	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	3640	**2023**	**10**
	Investment Name		
	Station B New Building		

Investment Description

Issue/Concern:
The Station B office on Eastern Avenue is an owned property in a good location but does not meet current building standards or operational requirements. The physical condition is considered good but the utilization and functionality is challenged. The office space no longer meets the needs of the staff currently working out of the facility. The new building will be able to provide the needed functionality and safety for the staff to carry out their tasks.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 12.28%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 49%.

Functional Obsolescence – Site: The property is divided into two separate parts. The first part consists of approximately 0.7 acres completely fenced off including a secure gate station located adjacent to the site on the northwest corner. The reminder of the site consists of 3.2 acres and is used as an operations depot. The site does not meet operational requirements for size and vehicular circulation. One point of access is provided to the site which poses circulation difficulties and poses operational inefficiencies. The yard size is marginally smaller than EGI standard yard size requirements. The current yard size is 2.25 acres. The EGI standard yard size is 2.5 acres. It was noted by EGI staff that the existing yard size is adequate for current operations. The existing building requires expansion by approximately 8,000 square feet to meet the need for current staff and EGI functional requirements.

Assets: 405 Eastern Avenue, Toronto, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work:
The project entails demolishing the existing facility and building a new single-storey building with underground parking to ensure much needed yard requirements for core operational needs such as fleet and equipment parking, aggregate bunkers, and yard. Underground parking will ensure the site is maximized for operations yard needs as land in Toronto's downtown is limited and requires efficient use of property. This will expand the usable existing yard. The new building footprint of approximately 20,000 square feet will ensure adequate interior storage/warehouse and fabrication space for operations, an operations muster/meeting space, washroom/locker facilities appropriately sized for the operation, and a larger office environment for site staff. The program will include currently missing elements such as a lunch room and meeting rooms. This new facility will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases.

The assets in scope are located at 405 Eastern Avenue, Toronto, ON. The nature of work is site improvements and construction and fit-up of a new building.

Resources:
Professional resources for design and engineering along with a contractor will be retained from the marketplace. Historically, EGI has engaged architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Solution Impact: The service life of the new facility would be 25 – 40 years, with the old building being demolished.

Project Timing:
The project duration is 36 months.
0 – 3 months: Programming and design development
3 – 9 months: Site plan agreement, permit and tender documents
9 – 12 months: Permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
30 – 36 months: Old building demolition and remaining site improvements

Risks include contractor delays and material delivery delays or defects.

Expenditures:
The total cost for the project is $41.9 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI projects. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. Project costs are based on a Class 5 estimate.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
3640	**2023**	**10**

Investment Name

Station B New Building

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Station B New Building	$ 41,850,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 10,000,000	$ 20,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value
Cost Avoidance OPEX (CA)	47,678
Employee Productivity (CA)	2,776
Avoided GHG Emissions (CA)	29
Cost Avoidance CAPEX (CA)	0
Budget Savings CAPEX (CA)	0
Budget Savings OPEX (CA)	0
Revenue Impact (CA)	0
Energy Efficiency (CA)	(121)
Total Investment Cost (CA)	(37,595)
Total	**12,766**

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	100621	**2023**	**10**
	Investment Name		
	Dawn Administrative Centre		

Investment Description

Issue/Concern: The Dawn admin centre on Bentpath Line is an owned property in a good location but does not meet current building standards or operational requirements. The physical condition is considered poor and the utilization and functionality is challenged. The office space no longer sufficiently accommodates current and future staffing needs of the facility.

Physical Obsolescence: The acceptable Enbridge Gas Inc. (EGI) standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 16.95%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 28%.

Functional Obsolescence – Site: The area occupied by the building is separated from the adjacent functions with metal fence complete with barb wire. The building occupies approximately 7.5% of 233,541 SF fenced site area.
The two driveways to the south and east of the building act as main entry and exit only servicing visitors and employees. There are four access points from the south and east driveway that lead to the front parking lot. The parking area consists of 68 parking spaces and is considered adequate to accommodate staff and visitors.
There is no yard associated with the building due to its unique function as an office building with no industrial components.
The building is located in the underground gas storage zone. It was reported by staff the proximity of the building to the underground gas storage is of concern to staff and relocation to an area outside the storage zone is desirable.

Assets: 3332 Bentpath Line, Tupperville, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: Build new facility elsewhere on the Dawn campus. The current Asset Management Plan has allocated funds in 2021 and 2022 to fulfill the strategy. This presents the safest, most cost-effective solution for maintaining a Category 1 facility.

Solution Impact: The service life of the new facility will be 25-40 years.

Timing and Execution Risks:
The Project duration is 36 months:
0 – 3 months: Programming and design development
3 – 9 months: Site plan agreement, permit and tender documents
9 – 12 months: Permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
30 – 36 months: Old building demolition and remaining site improvements

Risks include contractor delays and material delivery delays or defects.

Expenditures:
The total cost for the project is $12M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and estimated land values are based on marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources:
External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_02 - Chatham
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100621	**2023**	**10**

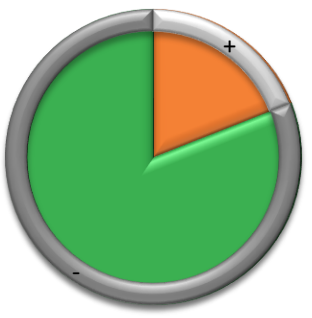
Investment Name

Dawn Administrative Centre

Alternative Spend Profile - Recommended

Name									Net Base Capex O (CA)	
Dawn Administrative Centre									$	12,000,000
Account Type	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ 12,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value
Cost Avoidance OPEX (CA)	2,020
Cost Avoidance CAPEX (CA)	0
Budget Savings CAPEX (CA)	0
Budget Savings OPEX (CA)	0
Revenue Impact (CA)	0
Total Investment Cost (CA)	(8,596)
Total	**(6,576)**

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	101136	**2023**	**10**
	Investment Name		
	New London Site		

Investment Description

Issue/Concern/Opportunity: This project will allow for potential consolidation currently under review of four operational sites in the Union rate zones into a single facility.
Boundary analysis still ongoing and investment details will continually be updated as strategy progresses.
Functional Obsolescence – Building: N/A
Functional Obsolescence – Site: N/A

Assets: N/A

Related Program: N/A

Recommended Alternative Description

Scope of Work:

This project requires selling existing assets, purchasing a property suitable in size (approximately 7 to 10 acres) and building a new 44,000 sq. ft. building that will consist of administration, warehouse, welding and fabrication facilities. The preferred strategy is to correct physical and functional deficiencies by purchasing a new site and build a new facility on the new site.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, Enbridge Gas Inc. (EGI), has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Solution Impact: This option corrects operational and workplace inefficiencies by consolidating existing facilities. The new facility will use less energy and emit less greenhouse gases. The service life for the new facility will be 25 to 40 years.

Project Timing & Execution Risks

Timing: The total project duration is 30 months:
0 – 3 months: Programming, design development, and location analysis
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
Post-occupancy disposition of property

Risks include contractor delays and material delivery delays or defects.

Expenditures:
The total cost for the project is $39.2M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
New London Site	$ 39,161,600

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ 9,405,000	$ 12,891,100	$ 15,245,500	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

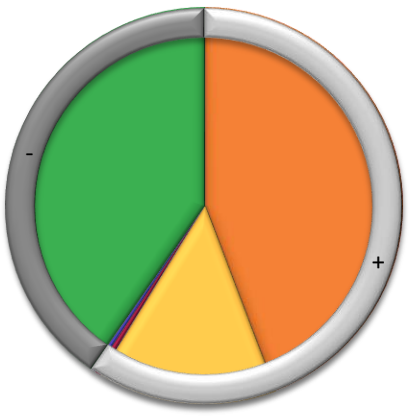
Investment Summary Report

Investment Code	Report Start Year	Number of Years
101136	**2023**	**10**

Investment Name

New London Site

Alternative Value - Recommended



Value Function Measure	Value
Cost Avoidance OPEX (CA)	33,927
Employee Productivity (CA)	11,182
Energy Efficiency (CA)	392
Avoided GHG Emissions (CA)	273
Cost Avoidance CAPEX (CA)	0
Budget Savings CAPEX (CA)	0
Budget Savings OPEX (CA)	0
Revenue Impact (CA)	0
Total Investment Cost (CA)	(30,926)
Total	**14,848**

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	737272	**2023**	**10**
	Investment Name		
	Kennedy Road New Build		

Investment Description

Issue/Concern:
Overall, the existing building at the Kennedy Road facility is too small to meet current EGI standards. The separation of offices and warehouse into two separate buildings is not convenient for staff and causes operational and workplace difficulties and inefficiencies. The configuration of site functions and circulation is inefficient. The yard area is too small to meet current EGI standards. Building expansion on the same property will further reduce the size of the yard area and will cause additional pressure on parking and circulation. Based on the site deficiencies and space limitations, relocation to another property is recommended. This option may no longer be possible so further analysis is required depending on the ability to procure adjacent property or appropriately-sized property nearby. The analysis will look at the possible vertical industrial solution to meet the needs of the business.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a FCI of 0 to 5%. The current FCI of the facility based on this study is 6.51%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility AI is 95%. Based on the FCI/AI graph, the current recommendation for the existing facility is to increase the site area by purchasing the adjacent property, demolish existing building, and re-build the facility on the combined sites to accommodate current EGI standards.

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. Access and exit from Kennedy is difficult and poses operational inefficiencies.The yard size is smaller than EGI standard yard size requirements. The current yard size is 1.3 acres. EGI standard yard size is 2.5 acres. The existing building requires expansion by approximately 11,000 square feet to meet the need for current staff and EGI functional requirements. Building additions on the property entail further reduction in the yard and parking areas.

Asset: 3157 Kennedy Road, Scarborough, ON.

Related Program:N/A

Recommended Alternative Description

Scope of Work: Purchase the vacant adjacent property, if available, otherwise purchase a new site and dispose of current site after new facility complete. Required size of new property is 5+ acres.

The project will correct operational and workplace inefficiencies, using less energy and emit less greenhouse gases on the combined site. This strategy will leverage current site improvements and keep land acquisition costs to a minimum by joining the currently vacant neighboring property.

The assets in scope are located at 3157 Kennedy Road, Scarborough, ON. The nature of work includes development of the adjacent property and construction and fit-up of a new building.

Solution Impact: The service life of the new facility will be 25-40 years.

Timing and Execution Risks:
The Project duration is 36 months:
0 – 3 months: Programming, design development
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit & tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
30 – 36 months: Demolition of old facility

Risks include contractor delays and material delivery delays or defects.

Expenditures:
The total cost for the project is $38M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and estimated land values are based on marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources:
External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
737272	**2023**	**10**

Investment Name

Kennedy Road New Build

Alternative Spend Profile - Recommended

Name									Net Base Capex O (CA)
Kennedy Road New Build									$ 37,974,500

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 150,000	$ -	$ 12,694,500	$ 18,000,000	$ 7,000,000	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 500,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value
Cost Avoidance OPEX (CA)	7,694
Cost Avoidance CAPEX (CA)	0
Budget Savings CAPEX (CA)	0
Budget Savings OPEX (CA)	0
Revenue Impact (CA)	0
Avoided GHG Emissions (CA)	(34)
Energy Efficiency (CA)	(208)
Total Investment Cost (CA)	(32,995)
Total	**(25,544)**

Report Generation Date: 7/20/2023

Investment Code	Report Start Year	Number of Years
737374	**2023**	**10**

Investment Summary Report

Investment Name

Ottawa - New Building

Investment Description

Issue/Concern:

Coventry Road
The office building in Ottawa is an owned facility that is in physically fair condition. The facility's functionality is sound but there is excess space. In addition, the furniture and finishings do not meet functional standards. The office is in a good location to serve the respective area, but there is duplication in coverage between the SMOC and Coventry Road facilities.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0, anything between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index is 43%, considered marginally correctable at current location without consideration of other factors including adequacy of land size and the Functional Condition Index.

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation within the site. The yard size is smaller than EGI standard yard size requirements. The current yard size is 1.42 acres. EGI standard yard size is 2.5 acres. Building is in average condition and functionally sound (building has excess area). The site does not meet non-functional standards (furniture standards, finishes etc.) The site is in a good location but is no longer optimized for best use. There is potential for consolidation with the SMOC facility on 90 Bill Leatham Drive, Nepean, ON.

SMOC
SMOC is an owned facility in physically fair condition. The facility's functionality is sound, however, there is unused/excess space. In addition, the furniture and finishings do not meet non-functional standards (furniture standards, finishes etc.). The office is in a good location to serve its respective area, but there is duplication in coverage between this office and the office at Coventry Road.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. Anything between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index is 24% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the Functional Condition Index.

Functional Obsolescence – Site: The configuration of site functions and circulation is inefficient and poses a safety hazard. The yard area is too small to meet current EGI standards. The building is in average condition and is functionally sound (building has excess area). The building does not meet non-functional standards (furniture standards, finishes etc.) It is in a good location but there is potential for consolidation with the Coventry Road facility.

Assets: 400 Coventry Road, Ottawa, ON, and 90 Bill Leatham Drive, Nepean, ON (SMOC)
Related Program: N/A

Recommended Alternative Description

Eastern Region Consolidated Facility Project
Scope of Work:
This project requires selling both the SMOC and Coventry Road properties, purchasing a property suitable in size (approx. 7 acres) and building a new 70,000 sq. ft. building that will consist of administration, warehouse, welding, and fabrication facilities. The assets in scope are located at 400 Coventry Road, Ottawa, ON, and 90 Bill Leatham Drive, Nepean, ON (SMOC). The nature of work is development of a new property and the construction and fit-up of a new building.

Solution Impact: This option corrects operational and workplace inefficiencies by consolidating SMOC and Coventry redundancies. The new facility will use less energy and emit less greenhouse gases. The service life for the new facility will be 25-40 years.

Timing: The total Project duration is 30 months:
0 – 3 months: Programming, design development, location analysis
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
Post-occupancy disposition of property

Risks include contractor delays and material delivery delays or defects.

Expenditures: The total cost for the project is $43.4M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
737374	**2023**	**10**

Investment Name

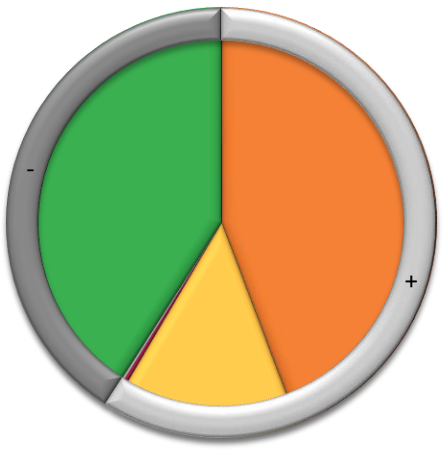
Ottawa - New Building

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Ottawa - New Building	$ 43,339,784

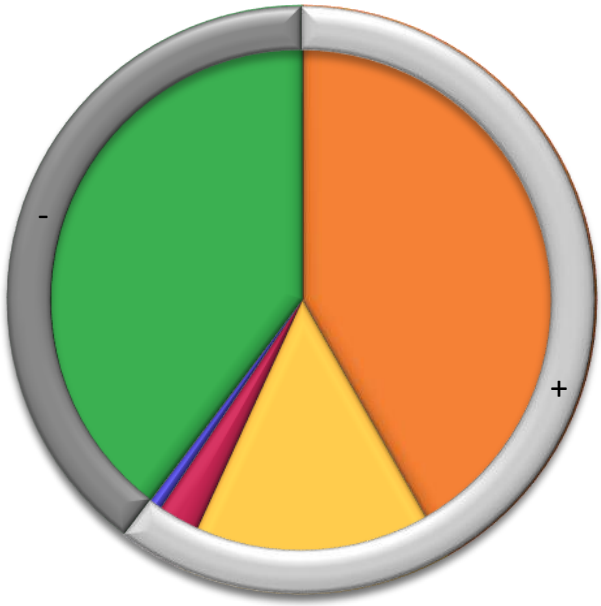
Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 25,439,784	$ 10,400,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 350,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value
Cost Avoidance OPEX (CA)	42,745
Employee Productivity (CA)	13,755
Energy Efficiency (CA)	351
Avoided GHG Emissions (CA)	225
Employee And Contractor Safety Risk	0
Cost Avoidance CAPEX (CA)	0
Budget Savings CAPEX (CA)	0
Budget Savings OPEX (CA)	0
Revenue Impact (CA)	0
Total Investment Cost (CA)	(39,493)
Total	**17,583**

Report Generation Date: 7/20/2023



Investment Summary Report	Investment Code	Report Start Year	Number of Years
	739714	**2023**	**10**
	Investment Name		
	GTA East - New Build - Peterborough		

Investment Description

Issue/Concern/Opportunity: This is a joint project between LEG and LUG (Investment code 100677). Total project costs are $11.4M
Justification:Operations boundary location committee recommendation. Consolidated facility in the Eastern region and possible retirement of two alternate existing facilities.
Assets: 1 new operations site and building. 5 acres, 12,000 sqft.
Related Investments: LUG twin investment 100677
Issue/Concern: Operations boundary realignment to operate efficiently the combined operations teams. Possible retirement of two redundant facilities.

Recommended Alternative Description

Scope of Work: Purchase a new 5 acre site and build a new 12,000 sf facility.

Site 1 consolidated Facility
Scope:
This Project requires purchasing a property suitable in size (approx. 5 acres) and building a new 12,000 sq. ft. building that will consist of administration facilities. This option corrects operational and workplace inefficiencies by consolidating redundant sites and optimizing operation boundaries. The new facility will use less energy and emit less greenhouse gases. The service life for the new facility will be 50 years.
Two existing assets in scope and one new facility. The nature of work is development of a new property and the construction and fit-up of a new building. The total Project duration is 30 months as described below:
0 – 3 months: Programming, design development, location analysis
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
Post-occupancy disposition of property
Expenditures
The total cost for the Project is $11.4M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and land values using marketplace comparisons. The Project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The Project costs are based on a Class 5 estimate.
Resources
External professional resources for design and engineering along with a construction company will be contracted for the Project. Historically EGD has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	REWS - CTA (Non-Core)
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
GTA East - New Build - Peterborough	$ 11,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 200,000	$-	$-	$ 10,800,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

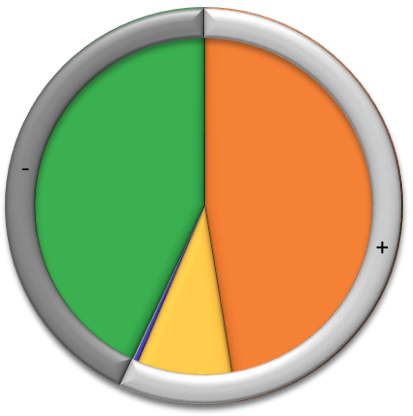
Investment Summary Report

Investment Code	Report Start Year	Number of Years
739714	**2023**	**10**

Investment Name

GTA East - New Build - Peterborough

Alternative Value - Recommended



Value Function Measure	Value
Cost Avoidance OPEX (CA)	9,231
Employee Productivity (CA)	1,744
Avoided GHG Emissions (CA)	86
Energy Efficiency (CA)	25
Cost Avoidance CAPEX (CA)	0
Budget Savings CAPEX (CA)	0
Budget Savings OPEX (CA)	0
Revenue Impact (CA)	0
Total Investment Cost (CA)	(8,365)
Total	**2,720**

Report Generation Date: 8/8/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	739715	**2023**	**10**
	Investment Name		
	GTA West - New Build - Halton Hills		

Investment Description

Issue/Concern/Opportunity: Total project costs are $33M
Justification: Operations boundary location committee recommendation. Consolidated facility in the West/Niagara region and retirement of three alternate existing facilities (Burlington, Brampton, and Milton).
Assets: 1 new operations site and building. 10 acres, 26,000 sqft (12,000 sqft ops, 14,000 sqft office).
Office for 70 office and 70 field staff.
Related Investments: New GTA West Site (100548)
Issue/Concern: Operations boundary realignment to operate efficiently the combined operations teams. Possible retirement of two redundant facilities.

Recommended Alternative Description

Scope of Work: Purchase a new 10 acre site and build a new 26,000 sf facility.

Site 1 consolidated Facility
Scope:
This Project requires purchasing a property suitable in size (approx. 10 acres) and building a new 26,000 sq. ft. building that will consist of administration, warehouse, welding and fabrication facilities. This option corrects operational and workplace inefficiencies by consolidating redundant sites and optimizing operation boundaries. The new facility will use less energy and emit less greenhouse gases. The service life for the new facility will be 50 years.
Two existing assets in scope and one new facility. The nature of work is development of a new property and the construction and fit-up of a new building. The total Project duration is 30 months as described below:
0 – 3 months: Programming, design development, location analysis
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
Post-occupancy disposition of property
Expenditures
The total cost for the Project is $33M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and land values using marketplace comparisons. The Project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The Project costs are based on a Class 5 estimate.
Resources
External professional resources for design and engineering along with a construction company will be contracted for the Project. Historically EGD has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	01 - All
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
GTA West - New Build - Halton Hills	$ 32,885,216

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 385,216	$ -	$ 20,000,000	$ 12,500,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

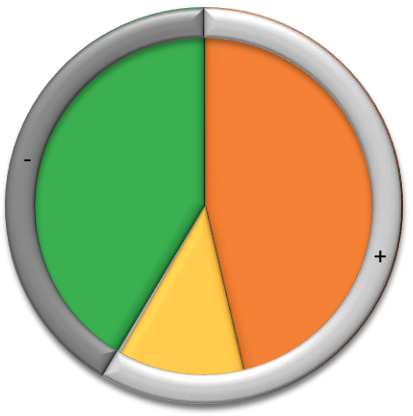
Investment Summary Report

Investment Code	Report Start Year	Number of Years
739715	**2023**	**10**

Investment Name

GTA West - New Build - Halton Hills

Alternative Value - Recommended



Value Function Measure	Value
Cost Avoidance OPEX (CA)	29,790
Employee Productivity (CA)	7,694
Energy Efficiency (CA)	81
Avoided GHG Emissions (CA)	83
Cost Avoidance CAPEX (CA)	0
Budget Savings CAPEX (CA)	0
Budget Savings OPEX (CA)	0
Revenue Impact (CA)	0
Total Investment Cost (CA)	(28,856)
Total	**8,793**

Report Generation Date: 8/8/2023

Investment Summary Report

Investment Code	Report Start Year	Number of Years
102291	**2023**	**10**

Investment Name

Contract Market Harmonization

Investment Description

Issue/Concern/Opportunity: The OEB MAADs decision specified that EGI shall file a proposal for rate harmonization in its next rebasing application. This was not a requirement to harmonize rates, but a requirement to file a proposal to harmonize. In order to harmonize contract market rates, services must also be harmonized. If the proposal filed as part of 2024 Rebasing is approved, this project will be required to implement the approved rates and services in the systems listed below.

Assets: EnTRAC, URICA, Enerline, CARE, ConTrax, GDAR, SAP- CIS, SAP-ERP, Oracle Financials, Data Marts are examples of the systems impacted

Related Program: Contract Market Systems - Technology Obsolescence #736942, Rates and Service Harmonization Project.

Recommended Alternative Description

Scope of Work : Currently, Enbridge Gas Inc (EGI) has 3 different rate zones (EGD, Union North, Union South), 11 separate service designs and 43 rate classes. This results in complex business and accounting processes. This project will implement changes to several EGI systems to implement a harmonized model with a single rate zone for EGI, 5 common service designs and 15 rate classes. The proposed services are designed using the best features from the existing EGD and Union contract rate services. The services have been simplified and aligned across the franchise to provide consistent and improved customer experience and unnecessary complexities.
This project, in conjunction with the Contract Market - Technology Obsolescence Project, is required to meet expectations of end-use customers of our new integrated gas distribution company. Many of our large-volume customers transact with us on both legacy Enbridge Gas Distribution and legacy Union Gas systems. There are different rates, business processes and applications that they have to understand and work with and are expecting Enbridge to harmonize to make things easier for them. Customers in all areas of the franchise will receive consistent service with common design and service elements. For example, bundled direct purchase rules will be the same regardless of location, where today their rules are different. EGI will benefit from less complexity in the services and rates we offer customers. This will make training and learning easier, simplifies jobs and the detailed business knowledge required within roles. It will facilitate harmonized business processes and allows for improved cross functional understanding between roles. System complexity will also be reduced with harmonized rates and services. This should reduce risk when making system changes and will simplify testing and TIS training and learning of the current complex business rules supporting the current EGD and Union sets of rates and services across multiple applications.
This project will follow TIS project methodologies as developed and governed by the Project Management Office.
This functionality will be enabled in conjunction with the Contract Market Systems - Technology Obsolescence project.
Several systems are impacted given the changes required:
ConTrax/CARE/GDAR/Enerline - Legacy UG applications that perform contracting, billing and gas management/nominations functions, including customer facing portal.
EnTRAC/Urica/GDAR - Legacy EGD applications that perform contracting and gas management/nominations function, including customer facing portals.
These applications must be integrated to allow for the harmonization of rates and services and a single customer portal. If they are not integrated, EGI will have to make changes to multiple applications that facilitate the same business processes. In addition, some of the proposals for rate and service harmonization would not be able to be implemented as all customers/contracts must be in a single system (eg. pooling).
In addition, there will be changes required to downstream systems such as gas accounting, QRAM, financial reporting to align with the harmonized rates and services.
Resources: Project Manager, Business Analysts, Business Systems Support Team, Customer Care SMEs, Regulatory SMEs, Finance SMEs, TIS SMEs, Energy Services SMEs, Finance SMEs, Enterprise Architecture, Solutions Architecture, Data & Analytics, Report Developers, AMS provider, Solutions Integrator, Audit, Testing, Organizational Change Management (OCM)

Solution Impact: EGI currently has 3 Rate Zones, 11 Separate Service Designs and 43 Rate Classes. This project will implement the required changes to enable 1 Rate Zone for EGI with 5 Common Service Designs, and 15 Rate Classes.

Project Timing & Execution Risks: Project expected to start late 2023, pending approval of Rate and Service Design by the OEB. A key dependency is the Contract Market - Technology Obsolescence Project. In order to harmonize rates and services, EGI must consolidate and modernize the contract rate billing, contracting, GDAR and gas management/nominations applications. Target implementation date is Q2 2026. Project milestones for design, build, test and delivery to be developed once project approved, team established, and project initiated.
Risks include resource constraints, competing priorities, harmonization not approved by OEB or not approved as submitted by EGI.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS Business Solutions
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	TIS Business Solutions
	Asset Class (EGI)	TIS
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Contract Market Harmonization	$ 14,860,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 2,100,000	$ 5,000,000	$ 5,000,000	$ 2,760,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

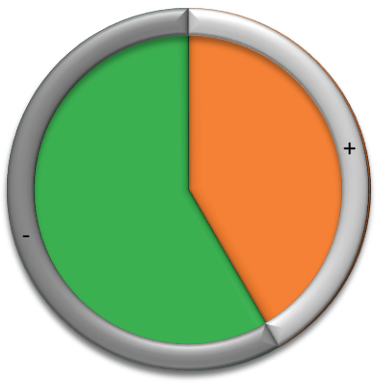
Investment Summary Report

Investment Code	Report Start Year	Number of Years
102291	**2023**	**10**

Investment Name

Contract Market Harmonization

Alternative Value - Recommended



Value Function Measure	Value
Cost Avoidance OPEX (CA)	9,110
Cost Avoidance CAPEX (CA)	0
Budget Savings CAPEX (CA)	0
Budget Savings OPEX (CA)	0
Revenue Impact (CA)	0
Public Safety Risk	0
Employee Productivity (CA)	0
Total Investment Cost (CA)	(12,753)
Total	**(3,643)**

Report Generation Date: 7/20/2023

Investment Code	Report Start Year	Number of Years
102364	**2023**	**10**

Investment Summary Report

Investment Name

Records Management Technology Obsolescence (2024-2026)

Investment Description

Issue/Concern/Opportunity:
The Records Management technologies host information about EGI gas carrying asset which are critical to drive integrity and operation of these assets. In addition, the information is used by the Integrity group to determine asset condition which will inform the asset life cycle strategies used to develop the 10 year Asset Plan with focus on safe and reliable operations of EGI assets. The Records Management technologies is made up of multiple systems which will become vendor unsupported between 2024 to 2026 and requires upgrades to reduce technology complexity, cyber risk, and to enable process optimization. Failure to maintain software warranty will increase the likelihood of system failures, increase outages, degraded performance and increase vulnerability to cybersecurity attacks.

The objective of the Records Management (Asset Records) Technology Obsolescence project is to align the key systems and high level process for gas carrying asset records which are used to support Operations in performing maintenance, and construction work as well as Engineering to conduct analysis and produce asset plans. This will be enabled through the selection of an integrated suite of applications that satisfy all technical and business requirements.

Assets:
TIS Business Solutions, examples of the core systems impacted:
-ESRI ArcServer GIS (Packaged Software) 10.8 (2026 retirement)
-Hexagon GIS (Packaged Software) G/Technology (2024 retirement)
-iViewer (Custom)
-ProjectWise Connect (Packaged Software) (2024 retirement)

Related Program: N/A

Recommended Alternative Description

Scope of Work :
The scope and objective of the Records Management (Asset Records) Technology Obsolescence project is to address the technology obsolescence and align the key systems for gas carrying asset records. This will be enabled through the selection of an integrated suite of applications that satisfy all technical and business requirements. The work will consist of upgrading software to the latest supported versions as well as incorporate the opportunities to optimize business processes by leveraging new capabilities offered by the software.

The initiative will follow TIS project methodologies as developed and governed by the Project Management Office, including, signed charter and a project plan covering the activities of design, build, test and implementation.

Benefits:
EGI will be able to leverage advancements in technology which could provide further benefits in optimizing business processes. As such the following benefits are estimated: Technology savings of $975k annual savings related to a reduction in technology, licenses, and infrastructure. Business savings are comprised of $1,000,000 related to drafting efficiencies in Distribution Operations; $400,000 related to Records Management team savings in Engineering & STO; $50,000 related to efficiencies in Engineering Construction/Drafting and Capital Development; all savings have been derived using an ~8% rate reduction

Resources:
Project Managers, Enterprise Architecture, System Integrators, Operations SMEs, Asset Records SMEs, TIS SMEs, Vendor Professional Services, External Contractors

Solution Impact:
This will impact Operations and Engineering employees as well as third-party alliance partners who require asset records to perform their work. This will also impact teams within the organization that produce and manage asset records throughout the asset lifecycle, such as the Records Management team and Asset Integrity. The solution will implement the latest version of software where software bugs have been resolved and the technology would be compatible to the latest hardware thereby ensuring a more secure, reliable, and sustainable platform. With the upgrades there are advancements in software technology introducing new capabilities that will optimize business processes.

Project Timing & Execution Risks:
This project is expected to start in 2024. With design efforts starting January 2024 and in service target date of completion Dec 2026.

Risk: Competing priorities, resource constraints, and business cost pressures.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS EGI Business Solutions
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	TIS Business Solutions
	Asset Class (EGI)	TIS
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
102364	**2023**	**10**

Investment Name

Records Management Technology Obsolescence (2024-2026)

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
Records Management Technology Obsolescence (2024-2026)	$ 18,050,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 750,000	$ 8,650,000	$ 8,650,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value
Budget Savings OPEX (CA)	6,604
Public Safety Risk	1,058
Cost Avoidance CAPEX (CA)	0
Cost Avoidance OPEX (CA)	0
Budget Savings CAPEX (CA)	0
Revenue Impact (CA)	0
Employee Productivity (CA)	0
Total Investment Cost (CA)	(16,768)
Total	**(9,106)**

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	736081	**2023**	**10**
	Investment Name		
	General Service Rebasing Changes		

Investment Description

Issue/Concern/Opportunity: The OEB MAADs decision specified that EGI shall file a proposal for rate harmonization in its next rebasing application. EGI believes that harmonizing rates will improve the customer experience for general service customers by simplifying rates, processes, and improved cost transparency. If the proposal filed as part of 2024 Rebasing is approved, this project will be required to implement the proposal in the EGI systems listed below.

Assets: TIS Business Solutions. CIS-SAP, Kubra, SAP-ERP, Oracle Financials, EnTRAC, ConTrax, GDAR, MyAccount, Data Marts (BBDM, CTDS, BW, EDW, etc), Guardian, Load Gathering, Synergee, Get Connected are examples of the systems impacted.

Related Program: N/A

Recommended Alternative Description

Scope of Work: Currently, Enbridge Gas Inc. (EGI) has three different rate zones (EGD, Union South and Union North) and six general service customer classes across eight rate categories. This results in complex business and accounting processes. This project will implement changes to several EGI systems to implement a harmonized model with a single rate zone for EGI, two customer classes (rate categories – Small Demand and General Demand) and harmonized rates. This will simplify rates for customers and related business and accounting processes such as QRAM. This project will follow TIS project methodologies as developed and governed by the Project Management Office.

Benefits include improved customer experience due to simplification of rates and improved cost transparency, business process simplification resulting from one set of terms and conditions of service across entire EGI franchise area, simplification of accounting processes including QRAM, forecasting, financial reporting, and easier to administer regulatory application and OEB review processes.

Resources: Project Manager, Business Analysts, Business Systems Support Team, Customer Care SMEs, Regulatory SMEs, Finance SMEs, TIS SMEs, Energy Services SMEs, Finance SMEs Enterprise Architecture, Solutions Architecture, Data & Analytics, Report Developers, AMS provider, Solutions Integrator, Audit, Testing, Organizational Change Management (OCM)

Solution Impact: This project will implement the required changes to enable a single rate zone for EGI with two customer classes (Rate Categories – Small Demand and General Demand) and the harmonization of general service rates.

Project Timing & Execution Risks:
-Project to start no later than January 2024, with approval from the OEB of General Service Rate Harmonization. Target implementation date Q2 2025. Project milestones for design, build, test and delivery to be developed once project approved, team established, and project initiated.
-Risks include resource constraints, competing priorities, OEB approval of harmonization as submitted by EGI.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS Business Solutions
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	TIS Business Solutions
	Asset Class (EGI)	TIS
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Net Base Capex O (CA)
General Service Rebasing Changes	$ 14,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 12,000,000	$ 2,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

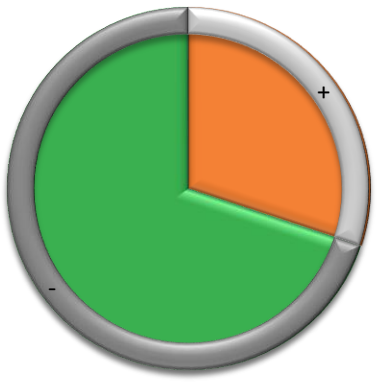
Investment Summary Report

Investment Code	Report Start Year	Number of Years
736081	**2023**	**10**

Investment Name

General Service Rebasing Changes

Alternative Value - Recommended



Value Function Measure	Value
Cost Avoidance OPEX (CA)	5,333
Cost Avoidance CAPEX (CA)	0
Budget Savings CAPEX (CA)	0
Budget Savings OPEX (CA)	0
Revenue Impact (CA)	0
Public Safety Risk	0
Employee Productivity (CA)	0
Total Investment Cost (CA)	(12,384)
Total	**(7,052)**

Report Generation Date: 7/20/2023

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	736942	**2023**	**10**
	Investment Name		
	Contract Market Systems - Technology Obsolescence		

Investment Description

Issue/Concern/Opportunity:
This project will consolidate the contracting, gas management/nominations and billing applications at EGI. The Contract to Cash processes are currently using aging and disparate systems for groups such as Large Volume Contracting, Gas Supply and Storage and Transmission Sales. This new platform and integrated systems will then enable Rate and Service Harmonization (if approved) and further enhance the customer experience, and reduce total cost of ownership.

Justification: Many of these systems are 20-30 years old and are built using technology that is or will become unsupported in the near future and requires upgrading. Failure to refresh aging systems and applications puts our business at risk with an increased chance of service outages, degraded performance, business and customer interruptions, increased costs, difficulty in acquiring support and ability to address cybersecurity risks.

Assets: Legacy (EGD&Union) Contract Management and Billing (EnTrac, URICA, ConTrax) and associated Legacy (LEGD&LUG) Gas Management systems (CARE, Enerline) will be replaced and/or modified by SAP modules and decommissioned (EGI may still retain this system name/brand for the customer facing portal, even if the underlying technology is replaced). New system integrations with CIS/SAP/Oracle/Cost of Gas, reporting, and data warehouse are examples of additional changes and systems impacted.

Related Investments: Contract Market Harmonization Project #102291

Recommended Alternative Description

Scope of Work:
Legacy (LEGD&LUG) Contract Management and Billing (EnTrac, URICA, ConTrax) and associated Legacy (LEGD&LUG) Gas Management systems (CARE, Enerline) will be replaced and/or modified by SAP modules and decommissioned. EGI may still retain this system name/brand for the customer facing portal, even if the underlying technology is replaced. New system integrations with CIS/SAP/Oracle, Cost of Gas, reporting, and data warehouse are examples of additional changes and systems impacted.
TIS benefits:
-Improved support and sustainment and cyber security.
- Decommissioning of servers and legacy applications.
- Reduced complexity and total cost of ownership for Contract and Gas Management systems and support
Business Benefits:
- Alignment, simplification and automation of business processes
- Easier to train staff, one set of unified processes and procedures
- Reduction in testing efforts, eliminating multiple systems and applications
- Improved customer experience and ease of use when transacting with Enbridge systems
- Reduced chance of service outages and degraded system performance

Resources: Customer Care Large Volume SME's, Energy Services Gas Management SME's, Finance, TIS SME's, Enterprise Architect, Data and Analytics Arch, Network and Security, Change Management, Project Manager, System Integrator, (Legal, Finance, Regulatory SME's as required)

Solution Impact: This project is required to align disparate and aging systems which must be replaced in order to ensure that contract market customers can continue to transact. Without this project, transactions such as contracting, gas management, and billing are at risk of service outage, degraded performance, cyber security risk, and increased cost of sustainment. This project also delivers a modernized technology platform that will enable the Contract Market Harmonization project which implements the proposed harmonized rates and services for the contract market. The implementation of this project and the Contract Market Harmonization project will deliver improved customer experience, simplified processes and aligned services on a modernized and reliable technology platform.

Project Timing & Execution Risks:
Timing- Project activities are expected to start in 2023, with the teams proving out the technology, and process mining tools, and reviewing business processes for standardization. An Request For Proposal (RFP) will be developed and selection the System Integrator (SI) for a project implementation date in 2026.
Risks- Competing priorities and resource constraints, continuity of resources on the project team to help mitigate schedule impacts for knowledge gaps (current state/future state, design/testing) and any potential rework as a result.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS Business Solutions
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	TIS Business Solutions
	Asset Class (EGI)	TIS
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	Yes

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
736942	**2023**	**10**

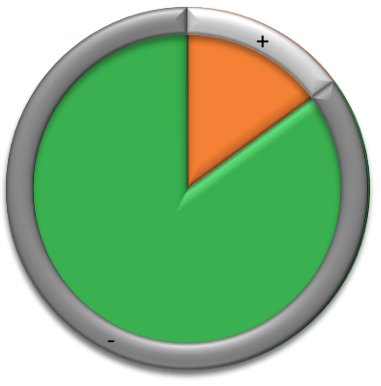
Investment Name

Contract Market Systems - Technology Obsolescence

Alternative Spend Profile - Recommended

Name									Net Base Capex O (CA)	
Contract Market Systems - Technology Obsolescence									$	54,010,000
Account Type	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Base CAPEX O	$ 8,220,000	$ 17,830,000	$ 17,830,000	$ 10,130,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value
Cost Avoidance OPEX (CA)	8,215
Cost Avoidance CAPEX (CA)	0
Budget Savings CAPEX (CA)	0
Budget Savings OPEX (CA)	0
Revenue Impact (CA)	0
Public Safety Risk	0
Employee Productivity (CA)	0
Total Investment Cost (CA)	(46,696)
Total	**(38,482)**

Report Generation Date: 7/20/2023

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking

Tr: 45

To provide a list of the projects in the summary table that are new, that have been removed, and why they have been removed.

Response:

Please see Table 1 which identifies investments that have been removed from or added to AMP Appendix A and reasons for their removal or addition.

Table 1
Investments Removed from or Added to AMP Appendix A

Investment ID	**Investment Name**	**Investment Stage**	**Added/ Removed from Appendix A**	**Reason for Addition/Removal from Appendix A**
7660	VPM - Erin Township	Executing	Removed	Multi-year phased project. Sections of the project have been deprioritized to balance forecast in 2024 and 26 and the total forecast is <$10 million.
1938	NPS 10 Glenridge Avenue, St. Catherines	Short Term Planning	Removed	Removed project from AMP forecast following a review with Integrity Management. Smaller scale mitigations to be implemented.
736530	Sudbury Lateral Integrity Digs 2023	Long Term Planning	Removed	Forecast has been reduced to <$10 million.
3610	Crowland Storage Transfer	Executing	Removed	Replaced with Investment # 13034
735335	GTAW Parkway Gate Station Rebuild Phase 2	Executing	Removed	Updated Forecast is < $10 million in the 2023-32 Forecast and therefore does not meet the criteria for inclusion of an investment summary report.
30523	SRP_North)Parry Sound_Seguin Trail_Reinforcement_ NPS6_8500m_4960k Pa	Short Term Planning	Removed	Updated Forecast is < $10 million in the 2023-32 Forecast and therefore does not meet the criteria for inclusion of an investment summary report.

Investment ID	Investment Name	Investment Stage	Added/ Removed from Appendix A	Reason for Addition/Removal from Appendix A
736075	WIND: Wheatley-1B - Panhandle Distribution Reinforcement - Wheatley Lateral Replacement and Reinforcement	Executing	Removed	Removed from AMP due to change in forecasted customer demands.
8701	Kelfield Operations Centre - Land Purchase	Short Term Planning	Removed	Removed from forecast to address cost pressures. Project will be given consideration during optimization of next revision to AMP
737226	Kelfield Operations Centre - New Building	Initial	Removed	Removed from forecast to address cost pressures. Project will be given consideration during optimization of next revision to AMP
501813	Kennedy Road Expansion	Executing	Removed	Project was split into two components. The >$10 million component is included under Investment # 737272
3642	SMOC/Coventry Facility Consolidation	Executing	Removed	Project was split into two components. The >$10 million component is included under Investment # 737374
8681	Thorold Regional Office - Building & Site	Short Term Planning	Removed	Project was split into two components. The >$10 million component is included under Investment # 737754
100709	Sudbury Regional Operations Centre	Short Term Planning	Removed	Updated Forecast is < $10 million in the 2023-32 Forecast and therefore does not meet the criteria for inclusion of an investment summary report.
6377	PCRW: Wells-Upgrade	Executing	Removed	Updated Forecast is < $10 million in the 2023-32 Forecast and therefore does not meet the criteria for inclusion of an investment summary report.
13034	SCRW:Station-Renewal In-Place	Executing	Added	Replaces Investment # 3610 - Reclassed as a Distribution Station as Compressor is to be abandoned.
740604	NPS20 KOL - Parliament St.	Executing	Added	Phasing of KOL Cherry to Bathurst project. Added 2023 In-service component.
10088	NPS 20 Lake Shore Replacement (Cherry to Bathurst)	Executing	Added	Clean up associated with 2022 construction activities for KOL Cherry to Bathurst originally forecasted to be completed in 2022.
10290	St. Laurent Phase 3 - Coventry/Cummings/St. Laurent (Plastic)	Executing	Added	Updated cost estimate exceeds $10 million threshold
737374	Ottawa – New Building	Executing	Added	Replaces Investment # 3642
737754	Thorold Operations Centre – New Building	Executing	Added	Split Investment 8681 into two investments. Inv # 737754 is the building component.

Investment ID	Investment Name	Investment Stage	Added/ Removed from Appendix A	Reason for Addition/Removal from Appendix A
739714	GTA East – New Build – Peterborough	Executing	Added	Added to AMP. Originally part of Integration Capital.
737272	Kennedy Road New Build	Executing	Added	Originally Investment # 501853
734676	SARN: 13F2020R Vidal St	Long Term Planning	Added	Updated cost estimate exceeds $10 million threshold
735022	Sarnia Industrial Station 2029 Rebuild	Long Term Planning	Added	Originally removed from 2023-32 Forecast based on market uncertainty. Added back during Capital Update.
30579	SRP_Southwest_Wonderland_New STN & MOP Upgrade	Short Term Planning	Added	New project added to AMP based on updated growth forecasts.
740055	Panhandle Regional Expansion Project – Dawn Facilities	Executing	Added	New investment created to track facilities at Dawn separately from pipeline.
739715	GTA West – New Build – Halton Hills	Executing	Added	Added to AMP. Originally part of Integration Capital.

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking

Tr: 46

To identify 2023 and 2024 expenditures in the table.

Response:

Please see Attachment 1.

Line No.	Investment Code	Appendix A Investment Name	AMP Planning Group	2023 Forecast Including Overheads	2023 Overhead Allocation	2024 Forecast Including Overheads	2024 Overhead Allocation	2023-2032 Forecast Including	2023-2032 Overhead	In Service Date
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
					Asset Class (EGI) - Compression Stations					
1	48715	Dawn C Compression Lifecycle	Significant Investments (>$10M)	$257,826	$57,826	$0	$0	$166,338,152	$41,178,152	2027
2	48732	Waubuno Compression Lifecycle	Value Driven - Fixed Timing	$324,860	$72,860	$2,355,233	$490,433	$29,218,620	$6,141,720	2025
3	100901	Dawn to Corunna	Value Driven - Fixed Timing	$186,492,347	$42,812,576	$13,845,083	$3,033,324	$200,337,430	$45,845,900	2023
4	734634	Dawn to Corunna (Dawn Tie-in)	Value Driven - Fixed Timing	$105,753,129	$23,718,491	$0	$0	$105,753,129	$23,718,491	2023
					Asset Class (EGI) - Distribution Pipe					
5	10088	NPS 20 Lake Shore Replacement (Cherry to Bathurst)	Value Driven - Fixed Timing	$20,896,371	$4,797,127	$0	$0	$20,896,371	$4,797,127	2022
6	10290	St. Laurent Phase 3 - Coventry/Cummings/St. Laurent (Plastic)	Value Driven - Fixed Timing	$0	$0	$23,376,683	$5,121,605	$25,033,190	$5,478,112	2024
7	10293	St. Laurent Phase 3 - North/South (NPS12/16 Steel)	Value Driven - Fixed Timing	$0	$0	$12,165,299	$2,665,299	$121,804,143	$26,503,360	2025
8	10294	St. Laurent Phase 4 - East/West (NPS12 Steel)	Value Driven - Fixed Timing	$0	$0	$51,230,980	$11,224,212	$53,906,876	$11,800,108	2024
9	11443	NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.	Value Driven - Value Framework	$0	$0	$0	$0	$30,613,585	$7,603,920	2026, subject to EDIMP assessment
10	100295	Div_04: NPS 8 Port Stanley, London, Replacement	Value Driven - Fixed Timing	$0	$0	$0	$0	$18,916,863	$4,025,457	2025, subject to EDIMP assessment
11	100339	A10: Wilson Avenue, Toronto, VSM Replacement	Executing - Re-Optimize	$0	$0	$0	$0	$106,992,932	$25,192,932	2026/2031, refer to Exhibit I.2.6- ED-100
12	503350	Moulton Replacement BU	Executing - Re-Optimize	$0	$0	$757,797	$157,797	$18,165,905	$3,813,905	2025
13	740604	NPS20 KOL - Parliament St.	Mandatory - Fixed Timing	$13,131,787	$3,014,631	$0	$0	$13,131,787	$3,014,631	2023
					Asset Class (EGI) - Distribution Stations					
14	13034	SCRW:Station-Renewal In-Place	Mandatory - Fixed Timing	$4,900,285	$1,124,946	$0	$0	$28,244,162	$6,171,173	2025
15	503369	Lisgar Station	Executing - Re-Optimize	$129,797	$29,797	$0	$0	$20,124,611	$4,242,407	2025
16	734676	SARN: 13F-220R Vidal St	Value Driven - Value Framework	$0	$0	$0	$0	$17,192,992	$4,712,992	2031
17	735022	Sarnia Industrial Station 2029 Rebuild	Value Driven - Fixed Timing	$0	$0	$0	$0	$14,849,863	$3,849,863	2029
					Asset Class (EGI) - Growth					
18	1024	NW 6581 Ottawa Reinforcement Phase 2 SRP	Mandatory - Fixed Timing	$0	$0	$0	$0	$70,698,549	$17,209,549	2029
19	30542	SRP_Southeast_Owen Sound_County Rd 40_Reinforcement_NPS1	Mandatory - Fixed Timing	$680,659	$152,659	$2,667,446	$555,446	$33,636,531	$7,236,531	2025
20	30579	SRP_Southwest_Wonderland_New STN & MOP Upgrade	Mandatory - Fixed Timing	$0	$0	$0	$0	$20,506,933	$4,306,933	2025
21	100703	SRP_LUG East_Kingston_Creekford Rd_Reinforcement_NPS 8_6200m_6 895kPa	Mandatory - Fixed Timing	$0	$0	$0	$0	$45,292,234	$11,283,270	2027
22	736259	Hamilton Reinforcement Project	Mandatory - Fixed Timing	$3,867,383	$867,383	$11,516,242	$2,398,042	$125,821,854	$26,713,062	2025
23	736975	Enbridge Gas Distribution System Hydrogen Feasibility Study	Value Driven - Fixed Timing	$2,359,281	$541,614	$5,762,510	$1,262,510	$15,315,942	$3,398,275	*2025 (corrected from 2022)
Line No.	Investment Code	Appendix A Investment Name	AMP Planning Group					2023-2032 Forecast Including Overheads	2023-2032 Overhead Allocation	In Service Date
					Asset Class (EGI) - LNG					
24	48709	Hagar KVGR and Cycle Mix Cooler	Value Driven - Value Framework	$0	$0	$0	$0	$24,740,190	$5,648,190	2032
25	48714	Hagar Cold Box	Value Driven - Value	$0	$0	$0	$0	$14,401,282	$3,401,282	2032
26	49955	Hagar JVG Compressor Upgrade	Value Driven - Value Framework	$0	$0	$0	$0	$20,873,854	$4,781,854	2032
					Asset Class (EGI) - Real Estate & Workplace Services					
27	3640	Station B New Building	Value Driven - Fixed Timing	$12,979,722	$2,979,722	$25,611,157	$5,611,157	$38,590,879	$8,590,879	2025
28	8782	VPC Core and Shell	Value Driven - Value Framework	$0	$0	$0	$0	$35,420,035	$9,420,035	2031
29	100621	Dawn Administrative Centre	Value Driven - Value Framework	$0	$0	$0	$0	$16,349,278	$4,349,278	2028
30	101136	New London Site	Executing - Re-Optimize	$0	$0	$0	$0	$49,500,658	$11,959,058	2026
31	737272	Kennedy Road New Build	Value Driven - Value Framework	$194,696	$44,696	$0	$0	$49,647,957	$11,803,457	2026
32	737374	Ottawa - New Building	Value Driven - Value Framework	$33,020,132	$7,580,348	$13,317,801	$2,917,801	$46,337,933	$10,498,150	2026
33	737754	Thorold Operations Centre - New Building	Value Driven - Value Framework	$64,899	$14,899	$832,363	$182,363	$21,533,430	$5,033,430	2026
34	739714	GTA East - New Build - Peterborough	Value Driven - Value Framework	$259,594	$59,594	$0	$0	$14,722,478	$3,722,478	2024
35	739715	GTA West - New Build - Halton Hills	Value Driven - Value Framework	$500,000	$114,784	$0	$0	$42,675,572	$9,790,356	2026
					Asset Class (EGI) - TIS					
36	102291	Contract Market Harmonization	Value Driven - Value Framework	$2,725,742	$625,742	$6,402,789	$1,402,789	$19,195,783	$4,335,783	2026
37	102364	Records Management Technology Obsolescence (2024-2026)	Value Driven - Value Framework	$0	$0	$960,418	$210,418	$23,566,261	$5,516,261	2026
38	736081	General Service Rebasing Changes	Value Driven - Value Framework	$0	$0	$15,366,694	$3,366,694	$17,914,329	$3,914,329	2025
39	736942	Contract Market Systems Technology	Mandatory - Fixed Timing	$10,669,331	$2,449,331	$22,832,346	$5,002,346	$69,786,961	$15,776,961	2026
					Asset Class (EGI) Transmission Pipe & Underground Storage					
40	48654	Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)	Mandatory - Fixed Timing	$0	$0	$1,262,995	$262,995	$251,357,572	$63,082,988	2027
41	49758	Panhandle Regional Expansion Project	Mandatory - Fixed Timing	$22,688,649	$5,088,649	$194,881,628	$40,580,457	$224,328,497	$47,088,489	2024
42	100086	Panhandle Line Replacement	Value Driven - Fixed Timing	$0	$0	$1,414,428	$294,528	$37,899,145	$8,128,866	2025
43	100699	Dawn Parkway Expansion Project (Dawn-Enniskillen NPS 48)	Mandatory - Fixed Timing	$0	$0	$0	$0	$332,803,728	$86,169,476	2029
44	735972	PREP: NPS 36 looping to Comber Transmission	Mandatory - Fixed Timing	$0	$0	$0	$0	$95,496,455	$25,496,455	2030
45	736923	Panhandle Regional Expansion Project - Leamington Interconnect	Mandatory - Fixed Timing	$64,456	$14,456	$217,399	$45,269	$118,751,452	$28,443,901	2026
46	740055	Panhandle Regional Expansion Project - Dawn Facilities	Mandatory - Fixed Timing	$38,931,658	$8,731,658	$5,382,040	$1,120,709	$92,044,573	$19,910,796	2025

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking

Tr: 49

To advise spend to date by asset category.

Response:

Please see below for an update to Exhibit 2, Tab 5, Schedule 3, Table 6 which presents 2023 year-to-date spend as of June 2023 by asset class:

Table 6
Utility Capital Expenditures by Asset Class 2019 Actual -2024 Test Year

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2023 YTD Jun Actual	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Compression Stations	EGI	25.5	26.5	42.3	106.8	321.8	91.9	46.3
2	Customer Connections	EGI	190.4	178.7	260.7	297.0	286.3	163.8	304.1
3	Distribution Pipe	EGI	175.1	192.8	447.2	477.5	237.5	116.3	357.1
4	Distribution Stations	EGI	39.7	61.4	91.2	97.1	67.5	14.6	83.5
5	Fleet & Equipment	EGI	26.3	20.2	26.7	30.6	8.9	6.1	31.5
6	Growth - Distribution System Reinforcement	EGI	144.1	70.0	48.5	69.4	55.1	22.7	85.2
7	Real Estate & Workplace Services	EGI	42.0	38.3	95.0	66.6	63.0	48.1	63.0
8	Technology Information Services (TIS)	EGI	48.9	22.7	22.8	28.1	47.1	23.1	102.4
9	Transmission Pipe and Underground Storage	EGI	20.3	33.5	79.5	62.6	79.0	13.9	69.2
10	Utilization	EGI	99.3	62.9	80.7	98.4	160.7	74.9	152.3
11	Extended Alliance Fixed Overhead	EGI	17.8	19.5	25.4	27.0	25.6	9.9	39.8
12	Capitalized Overheads	EGI	215.2	220.9	0.0	0.0	0.0	0.0	0.0
13	Integration Capital	EGI	21.7	39.8	63.0	26.5	20.0	9.3	0.0
14	Community Expansion	EGI	17.1	20.9	17.4	14.2	20.6	4.6	11.2
15	Other	EGI	3.9	(0.9)	10.5	1.1	34.3	2.4	124.6
16	Total		1,087.4	1,007.2	1,310.9	1,402.9	1,427.2	601.8	1,470.3

Notes:
(1) Capital expenditures are shown on an annual basis
(2) Expenditures are net of contributions and include IDC
(3) Overheads are included in the Asset Classes starting in 2021
(4) Panhandle Regional Expansion Project capex reductions of $34.2M in 2022, $22.7M in 2023 Bridge Year, $24.5M in 2023 Actual and $194.9M in 2024

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking

Tr: 52

To review undertaking JT4.25 to clarify revenue requirement for 2023 and 2024 on a standalone basis

Response:

In similar fashion to the response at JT4.25, Enbridge Gas has determined, on a best-efforts basis, the revenue requirement impact that 2023 in-service additions, in isolation, have in 2023 and 2024. This response is for illustrative purposes only and includes simplifying assumptions made in order to be responsive in a timely manner.

Please note that these estimated revenue requirement impacts do not consider any other corresponding impacts that would occur as a result of removing capital additions, such as changes in revenues, O&M (including municipal taxes), or term debt issuances/requirements.

The total revenue requirement impact of 2023 in-service additions in 2023, is a credit of approximately $5.6 million (or negative revenue requirement) as the CCA tax deduction (due to accelerated CCA) outweighs the impact of the increase in depreciation and cost of capital. In 2024, the 2023 in-service additions contribute approximately $131.8 million in revenue requirement. The change is due to the much lower CCA impact in 2024, related to the 2023 in-service additions, as well as the full-year impact of the cost of capital and depreciation. The details are provided in Attachment 1 and summarized in Table 1 below.

Table 1
Summary of Revenue Requirement applicable to 2023 In-Service Additions

($ millions)	2023 Revenue Requirement	2024 Revenue Requirement
Increase(Decrease) in Cost of Capital	19.6	69.4
Increase(Decrease) in Depreciation	41.3	60.5
Increase(Decrease) in Tax	(66.4)	2.0
Net Increase(Decrease) in Revenue Requirement	(5.6)	131.8

Revenue Requirement Scenarios

Line No.	Particulars ($ millions)	2023 Revenue Requirement			2024 Revenue Requirement		
		2023 As Filed	Excluding 100% 2023 Additions	Attributable to 2023 Additions	2024 As Filed	Excluding 100% 2023 Additions	Attributable to 2023 Additions
	Cost of Capital						
1	Rate Base	15,636.7	15,248.3	388.4	16,212.3	14,864.7	1,347.6
2	Required Rate of Return	5.76%	5.78%		5.87%	5.94%	
3	Required Return	901.3	881.8	19.6	952.2	882.8	69.4
	Cost of Service						
4	Gas Costs	3,047.3	3,047.3	0.0	3,228.0	3,228.0	0.0
5	Operations and Maintenance	1,021.7	1,021.7	0.0	1,054.0	1,054.0	0.0
6	Depreciation and Amortization	718.3	677.0	41.3	878.0	817.5	60.5
7	Fixed Financing Costs	4.0	4.0	0.0	4.0	4.0	0.0
8	Municipal and Other Taxes	122.4	122.4	0.0	126.2	126.2	0.0
9	Total	4,913.6	4,872.3	41.3	5,290.3	5,229.8	60.5
	Miscellaneous Operating and Non-Operating Revenue						
10	Other Operating Revenue	(63.2)	(63.2)	0.0	(64.3)	(64.3)	0.0
11	Other Income	-	-	-	-	-	-
12	Total	(63.2)	(63.2)	0.0	(64.3)	(64.3)	0.0
	Income Taxes on Earnings						
13	Excluding Tax Shield	136.2	199.2	(63.0)	162.9	186.7	(23.8)
14	Tax Shield Provided by Interest Expense	(109.7)	(107.7)	(2.0)	(110.8)	(101.6)	(9.2)
15	Total	26.6	91.5	(65.0)	52.1	85.1	(33.0)
	Taxes on (Deficiency)/Sufficiency						
16	Gross (Deficiency)/Sufficiency	43.3	37.7	5.6	(291.0)	(159.2)	(131.8)
17	Net (Deficiency)/Sufficiency	31.8	27.7	4.1	(213.9)	(117.0)	(96.9)
18	Total	(11.5)	(10.0)	(1.5)	77.1	42.2	34.9
19	Revenue Requirement	5,766.8	5,772.4	(5.6)	6,307.4	6,175.5	131.8
20	Increase(Decrease) in Revenue Requirement		5.6			(131.8)	
21	Contributions of additions to Revenue Requirement		(5.6)			131.8	
	Notes:						
	Increase(Decrease) in Cost of Capital		(19.6)	19.6		(69.4)	69.4
	Increase(Decrease) in Depreciation		(41.3)	41.3		(60.5)	60.5
	Increase(Decrease) in Tax		66.4	(66.4)		(2.0)	2.0
			5.6	(5.6)		(131.8)	131.8

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 80

To respond to Mr. Quinn's question about the 155 adjustment figure of PDO adjustment in FRPO-169.

Response:

Enbridge Gas understands the undertaking to request if the PDO adjustments are included in Exhibit I.4.7-FRPO-169, Attachment 1, at both line 4 and line 6 and to provide an explanation as to why they are / are not included in both lines. The question is seen at 13 Tr.76-77 (repeated at 13 Tr.79-80) and the OEB's confirmation that this is the only question to be answered is at 13 Tr.92.

The line items in question include the design day demands (Exhibit I.4.7-FRPO-169, Attachment 1, line 6), and the other system capacity changes (Exhibit I.4.7-FRPO-169, Attachment 1, line 4). Both line items have appropriately accounted for PDO, as follows:

- The design day demands include the ex-franchise and in-franchise demands on the Dawn-Parkway System, regardless of their supply obligation, including customers with a PDO.
- The other system capacity changes are calculated as the difference between the system capacity (Exhibit I.4.7-FRPO-169, Attachment 1, line 5), and the system capacity included in rates (Exhibit I.4.7-FRPO-169, Attachment 1, line 3). The system capacity is lower as a result of the reduction in the PDO, as the Company can serve less demands on the Dawn Parkway System. This reduction to the PDO was not included in the system capacity included in rates, and as such, is included in the other system capacity changes and does not represent a double count.

A detailed description of each line item is provided below. A summary of the design day demands and the derivation of the other system capacity for Winter 2013/2014 and Winter 2015/2016 is provided at Table 1. A copy of Exhibit I.4.7-FRPO-169, Attachment 1 is provided at Attachment 1 for reference.

Table 1
Summary of Dawn Parkway System Demand and Capacity

Line No.	Particulars (TJ/d)	Winter 2013/2014 (1) (a)	Winter 2015/2016 (2) (b)	Difference (c) = (b – a)
1	Total Forecasted Design Day Demand (3)	6,593	7,049	456
	Derivation of Other System Changes			
2	Total Dawn Parkway System Physical Capacity	6,164	6,533	369
3	Firm Receipts at Parkway (includes PDO)	639	481	(158)
4	System Capacity (line 2 + line 3) (4)	6,803	7,014	211
5	System Capacity included in Rates (5)	6,803	7,236	433
6	Other System Capacity Changes (line 5 – line 4) (6) (7)	0	(222)	(222)

Notes:
(1) EB-2011-0210, Exhibit J.G-1-7-4, Attachment 2.
(2) EB-2014-0261, Exhibit A, Tab 8, Schedule 1.
(3) Exhibit I.4.7-FRPO-169, Attachment 1, line 6.
(4) Exhibit I.4.7-FRPO-169, Attachment 1, line 5.
(5) Exhibit I.4.7-FRPO-169, Attachment 1, line 3. 2013 Cost of Service[1] capacity of 6,803 TJ/d plus incremental capacity from Brantford-Kirkwall/Parkway D Project[2] of 433 TJ/d.
(6) Includes 155 TJ/d PDO reduction, as per Exhibit J7.7.
(7) Exhibit I.4.7-FRPO-169, Attachment 1, line 4.

Design Day Demand – Exhibit I.4.7-FRPO-169, Attachment 1, line 6

The design day demand includes the in-franchise and ex-franchise demands for customers served from the Dawn Parkway System. Customer design day demands are located at various gate stations connected to and along the Dawn Parkway System. The design day demands include all in-franchise demands served from the Dawn Parkway System, regardless of their supply obligations, including customers with a PDO. The design day demands also include the ex-franchise M12 demands for those customers who transport their PDO to Parkway using M12 Dawn Parkway service. For the forecast Winter 2013/2014 to Winter 2015/2016, the design day demands served from the Dawn Parkway System increased from 6,593 TJ/d to 7,049 TJ/d, for a total increase of 456 TJ/d, as per Table 1, line 1.

[1] EB-2011-0210.
[2] EB-2012-0433/EB-2013-0074.

Other System Capacity Changes – Exhibit I.4.7-FRPO-169, Attachment 1, line 4
As described above, the other system capacity changes are calculated as the difference between the system capacity and the system capacity included in rates. A description of each is provided below.

System Capacity
The Dawn Parkway System capacity includes physical capacity of the Dawn Parkway System[3] plus the firm receipts at Parkway, including the PDO[4]. The Dawn Parkway System is used to transport supply from Dawn, Kirkwall, and Parkway to the various gate stations to serve the design day demand. As described at Exhibit J7.7, the Dawn Parkway System capacity is derived as the design day demand plus the capacity surplus or shortfall at Parkway. The Dawn Parkway System capacity is stated as a function of the design day demand it can serve based on the system's hydraulic analysis and the location and path the gas is travelling. A surplus or shortfall of capacity is calculated at Parkway and is added to or subtracted from the design day demand to become the system capacity.

A reduction of the PDO impacts the Dawn Parkway System capacity as follows:

- For customers without M12 service, a PDO reduction results in a reduction of Dawn Parkway System capacity and creates a system shortfall. There is a reduction to the firm receipts at Parkway (reducing the system capacity), while the in-franchise design day demands remain the same resulting in a system shortfall. The system shortfall was mitigated by the Dawn to Kirkwall M12 turnback used to facilitate the PDO reduction. The Dawn to Kirkwall M12 turnback, when converted into a Dawn to Parkway equivalent, resulted in an additional capacity reduction[5]. This situation results in a reduction in physical capacity (ex-franchise design day demand is reduced) and a reduction to the firm receipts at Parkway (supply is reduced), which nets to no impact to the system shortfall/surplus. For the forecast from Winter 2013/2014 to Winter 2015/2016, the firm receipts from Parkway served from the Dawn Parkway System decreased from 639 TJ/d to 481 TJ/d, for a total decrease of 158 TJ/d, as per Table 1, line 3.

[3] The physical capacity is calculated based on the design day demand in their physical location on the Dawn Parkway System. This demand does not all travel the full distance from Dawn to Parkway (discharge). In other words, the physical capacity does not represent the demands that can flow from Dawn to Parkway (discharge).
[4] The PDO is obligated in-franchise supply at Parkway and makes up a component of the total system supply. The PDO also increases the capacity of the Dawn Parkway System, as the Company is able to serve more demands on the system.
[5] For Winter 2015/2016, the Dawn to Kirkwall turnback of 138 TJ/d resulted in a Parkway equivalent volume of 123 TJ/d, as shown at Exhibit I.4.7-FRPO-169, column (c), line 9. This turnback resulted in a reduced Dawn Parkway System capacity of 15 TJ/d (138 TJ/d – 123 TJ/d).

- For customers who transport their PDO to Parkway using an M12 Dawn Parkway service, a PDO reduction results in a reduction of Dawn Parkway System capacity but no change to the system surplus/shortfall. There is a reduction to the firm receipts at Parkway (reducing the system capacity) and a reduction to the design day demands for the ex-franchise M12 turnback (reducing design day demands), while the design day demands for the in-franchise customers remain the same. This situation results in a reduction in physical capacity (ex-franchise design day demand is reduced) and a reduction to the firm receipts at Parkway (supply is reduced). However, in this instance the system shortfall does not need to be mitigated as the physical pipe previously built for the M12 contract is released back to the utility resulting in no change to the system shortfall.
- In both cases the Company is able to serve less demand from the system when the PDO is reduced. The PDO serves demand on the Dawn Parkway System and as such, when the PDO is reduced, the demands Enbridge Gas is able to serve is also reduced, which reduces the system capacity. Likewise, if the PDO increases, Enbridge Gas is able to serve more demands on the Dawn Parkway System, which increases the system capacity.

System Capacity Included in Rates

The total system capacity included in rates, as per Table 1, line 5, includes the capacity from Union's 2013 test year forecast of 6,803 TJ/d for Winter 2013/2014, as per Union's 2013 Cost of Service[6], and an additional 433 TJ/d for Winter 2015/2016 of incremental capacity from the Brantford-Kirkwall / Parkway D Project[7]. The intent of providing the other system capacity changes is to recognize the differences between the capacity included in rates, as calculated above, and the annual forecast Dawn Parkway System capacity.

For the forecast Winter 2013/2014 to Winter 2015/2016, there is a difference of (222) TJ/d related to other system capacity changes, as per Table 1, line 6. Included in this amount is a (155) TJ/d difference for the PDO, which includes 146 TJ/d of PDO reduction for customers without M12 service, as per Exhibit I.4.7-FRPO-169, column (b), line 8, and an additional 8 TJ/d of other PDO reductions due to normal year to year changes to in-franchise obligated supply. The details of the other system capacity changes of (222) TJ/d for Winter 2015/2016 are provided at Exhibit J7.7.

As the calculation of system capacity included in rates only includes the capacity from Union's 2013 Cost of Service[8] and incremental capacity from the Brantford-Kirkwall /

[6] EB-2011-0210.
[7] EB-2012-0433/EB-2013-0074.
[8] EB-2011-0210.

Parkway D Project[9], all other forecast changes on the Dawn Parkway System during the Winter 2013/2014 to Winter 2015/2016 time period are included in the other system capacity changes amount. As such, the other changes, including the reduction to the PDO, are reflected as part of the (222) TJ/d and do not represent a double count.

[9] EB-2012-0433/EB-2013-0074.

Filed: 2023-03-08
EB-2022-0200
Exhibit I.4.7-FRPO-169
Attachment 1
Page 1 of 1

Dawn Parkway System Capacity and Demand, PDO Shift Details, and PDO Demand Revenue Difference

Line No.	Particulars (TJ/d)	2013 Forecast W2013/2014 (a)	W2014/2015 (b)	W2015/2016 (c)	W2016/2017 (d)	W2017/2018 (e)	W2018/2019 (f)	W2019/2020 (g)	W2020/2021 (h)	W2021/2022 (i)	W2022/2023 (j)
	Dawn Parkway System										
	Included in Rates										
1	2013 Cost of Service (EB-2011-0210) Capacity	6,803	6,803	6,803	6,803	6,803	6,803	6,803	6,803	6,803	6,803
2	Incremental Dawn Parkway System Capacity (1)	-	-	433	876	1,332	1,332	1,332	1,332	1,332	1,332
3	Total	6,803	6,803	7,236	7,678	8,135	8,135	8,135	8,135	8,135	8,135
	Other Changes (No Impact to Rates)										
4	Other Dawn Parkway System Capacity Changes	-	(2)	(222)	(170)	(246)	(262)	(256)	(219)	(169)	(160)
	Annual Forecast										
5	Total Forecasted Dawn Parkway System Capacity (line 3 + line 4)	6,803	6,801	7,014	7,508	7,889	7,873	7,878	7,915	7,966	7,975
6	Total Forecasted Dawn Parkway System Demands	6,593	6,643	7,049	7,443	7,783	7,759	7,905	7,911	8,038	7,992
7	Forecast Dawn Parkway System Excess/(Shortfall) (line 5 - line 6) (2)	210 (3)	158	(35) (5)	65	106 (6)	114	(27)	4	(72)	(17)
	PDO Shift										
	Customers without M12 service										
8	Temporarily Available Capacity	-	146	23	13	-	-	-	-	-	-
9	Permanent Capacity (from Dawn-Kirkwall Turnback) (5)	-	0	123	133	200	200	200	200	200	200
10	Temporary Capacity (from exchange service)	-	-	-	-	-	-	-	-	-	27
11	Total	-	146 (4)	146	146	200	200	200	200	200	226
	Customers with M12 service - Permanent Capacity										
12	All Customers excluding TCE Halton Hills	-	19	19	19	19	19	19	19	19	19
13	TCE Halton Hills	-	48	48	48	62	132	132	132	132	132
14	Total	-	66	66	66	81	151	151	151	151	151
15	Total PDO Shift (line 11 + line 14)	-	212	212	212	280	350	350	350	350	377
	PDO Shift cost in Rates		2015 Rates	2016 Rates	2017 Rates	2018 Rates	2019 Rates	2020 Rates	2021 Rates	2022 Rates	2023 Rates
16	Dawn-Parkway Demand Costs ($000s)		5,143	5,694	6,720	9,726	10,956	11,117	11,273	11,391	11,630
17	Incremental Compressor Fuel Costs ($000s)		1,900	1,797	1,707	1,705	1,640	1,404	1,517	2,067	4,017
18	Firm Exchange Service ($000s)		-	-	-	-	-	-	-	-	1,067
19	Total		7,043	7,491	8,426	11,431	12,596	12,521	12,790	13,459	16,713
	Foregone Demand Revenue of M12 Dawn-Kirkwall Turnback										
20	Used for PDO Shift ($000s) (7)		580	4,669	5,937	9,993	11,217	11,379	11,535	11,654	11,896
21	Demand Revenue from Temporarily Available Capacity (line 8 x M12 D-P Rate x 12)		4563	796	531	0	0	0	0	0	0
22	Total		5,143	5,465	6,468	9,993	11,217	11,379	11,535	11,654	11,896
23	Demand Revenue Difference ($000s) (line 16 - line 22)		-	229	252	(267)	(261)	(262)	(261)	(263)	(266)

Notes:

(1) W2015/2016 - Incremental capacity resulting from the Brantford-Kirkwall / Parkway D Project of 433 TJ/d.
W2016/2017 - Incremental capacity resulting from the Dawn Parkway 2016 System Expansion Project of 443 TJ/d.
W2017/2018 - Incremental capacity resulting from the 2017 Dawn Parkway Project of 457 TJ/d.

(2) The PDO shift was reflected in Dawn Parkway excess/(shortfall) beginning W2015/2016.

(3) The W2013/2014 forecast filed in Union's 2013 Cost of Service proceeding (EB-2010-0210) included 210 TJ/d of excess Dawn Parkway capacity. In the EB-2011-0210 Decision, the OEB accepted Union's forecast and regulatory treatment. Union's 2013 Cost Allocation Study allocates Dawn Parkway demand costs in proportion to distance weighted design day demands. The 2013 allocation resulted in approximately 84% of costs allocated to Union's ex-franchise rate classes and 16% to Union's in-franchise rate classes.

(4) In accordance with the Settlement Framework for Reduction of Parkway Delivery Obligation ("PDO Framework") (EB-2013-0365) effective April 1, 2014, Union had temporarily available Dawn Parkway capacity which was used to facilitate 146 TJ/d of PDO shift. Parties agreed Union would include the demand and fuel costs associated with the 146 TJ/d of capacity in delivery rates. (PDO Framework, paragraph B1)

(5) Consistent with the PDO Framework, effective November 1, 2015 the temporarily available capacity was forecast to be used for other purposes leaving Parkway in a delivery shortfall position. Parties agreed that the demand and fuel costs associated with the temporarily available capacity would remain in delivery rates for Union to manage the Parkway delivery shortfall through the acquisition of incremental resources. M12 Dawn to Kirkwall turnback was to be used to first reduce the Parkway delivery shortfall and then to further reduce the remaining PDO. All incremental costs associated with the incremental PDO reduction were recovered by Union in rates (or deferral account due to timing differences). (PDO Framework, Paragraph B2)

(6) As part of the 2017 Dawn-Parkway Expansion Project (EB-2015-0200), Union had forecast a surplus of 30,393 GJ/d on the Dawn Parkway System following the completion of the project. As part of the EB-2015-0200 Settlement Agreement, Union agreed to market the surplus capacity in accordance with the Storage and Transportation Access Rule (“STAR”) and credit the revenues to the project deferral account.

(7) Exhibit I.4.7-FRPO-16 Attachment 2, line 7.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 81

Enbridge to provide an answer as to whether there is double counting as between the PDO amount of 155 TJs included within line 4 and line 6, and to provide any appropriate commentary. Enbridge to provide an answer as to whether there is double counting as between the PDO amount of 155 TJs included within line 4 and line 6, and to provide any appropriate commentary.

Response:

At Tr. Vol. 13 92, Commissioner Moran determined that this undertaking and the expansion of J13.16 are not necessary at this time.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

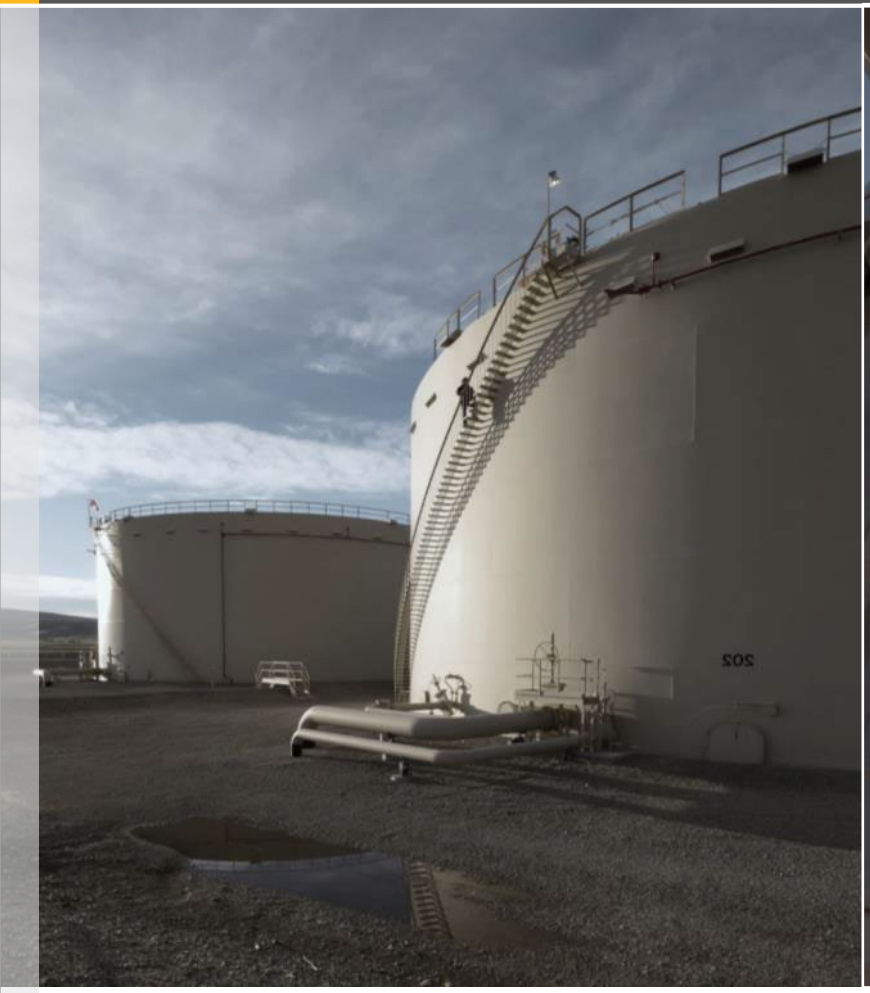
Tr: 91

To produce the slide deck associated with the 2022 year-end MP-01 asset management health check.

Response:

Please find the slide deck at Attachment 1.

MP-01 Asset Management Program



Q4 2022 Management Review

Pierce Jones

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Agenda

MP-01 January 17, 2022 Management Review

Agenda Item	Speaker	Purpose
Management Program Metrics Review	• Bob Wellington	Inform
YTD Objectives Progress	• Pierce Jones	Inform
Quarterly Risk Summary	• Ann-Marie Hessian	Inform
Compliance Management Update • Legal and Regulatory Changes	• Bob Wellington	Inform
Assurance Update: • YTD Assurance Plan Progress Update	• Bob Wellington	Inform
Resources Adequacy Confirmation	• Bob Wellington	Inform
Additional Topics: • 2023 Priorities • TotEx Update • IRP	• Bob Wellington • Mike Kreitner • Candice Case	Inform
Health Check Review	• Pierce Jones	Inform, Input

Management Program Metric Review

December YTD

Asset Management Program	Target	Actual	Progress Tracking	Comments
Core Capital Forecast vs Target (UGL)	603.1M	**693.7M		CC $22M over (Res New), DP $90M over (Integrity), DS $10M under, GTH $15M over, Util $6M under, TPUS $26M under (PREP)
Core Capital Forecast vs Target (EGD)	734.9M	**679.6M		CC $33M over (Res New), DP $64M under (St Laurent), Util $5M under, CS $37M under (Dawn to Corunna)
In-Service Capital vs Target (UGL)	544M	*648M		
In-Service Capital vs Target (EGD)	732M	*680M		
Core Capital Maintenance vs Target	369.8M	**290.3M		UGL REWS $26M under, EGD REWS $22M under, TIS $14M under
Failure Code Reporting - Distribution	70%	47%		*Expected improvements from AWS Phase 2 were not realized. A recommendation to remain status quo with back-end corrections has been made to Data Governance Council.*

Note For Capital Metrics:
Target = Budget, Actual = *Forecast EOY Target (8+4 Forecast), **2022 Actual

On Track
Off Plan - Path To Green Identified
At Risk - Mitigation Plan TBD
On-Hold
Not Yet Started

Objectives and Progress Update

2022 Capital Lookback

- Maintenance Capital
  - $79.5M below budget – some of this was required to offset higher growth spend
- ICM Capital
  - OEB disallowed ICM treatment or LTC for several projects
- Core EGD and UG Capital
  - Over budget by 3.8%
  - Substantial increase to Customer Connection, Integrity, Growth and Overhead forecasts
  - Emergent investments combined with higher costs for material and labour
- In-service capital not yet available

On Track
Off Plan - Path To Green Identified
At Risk - Mitigation Plan TBD
On Hold
Not Yet Started

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YTD Objectives Progress

Objective	YTD Progress	Status	Mitigation Plans (if required)
2023-2032 Asset Management Plan (AMP)	• Complete filed with Rebasing application	Complete	
Completion of Asset Management Maturity Assessment	• *No longer required for 2022*		• 2022 assessment was deemed not required as recent maturity assessments adequately identified areas of focus to improve maturity.
Value Based Decision Making Improvements (previously Roadmap for Value Framework Improvements)	• Complete	Complete	
Roadmap for Life Cycle Value	• Complete	Complete	
Execute Phase 2 of TotEx Value Model (Life Cycle Value) Roadmap	• TotEx Value Model completed for Onion Lake and communication on-going. • Shared revised project charter with Governance team and received endorsement for deliverables. • Early stages of data collection/scope development for Waubuno and Dawn C.		
Develop Multiyear Timeline for AMP	• Complete	Complete	

See Appendix for detailed Objectives and Progress Update

Q4 Risk Summary

Quarter over quarter changes

0 New Significant Risk in Q4
-

2 Emerging Risks in Q4
Fisher 627 Regulator Bolts Fracture due to Manufacturing Defects
Vidal St Walking Bridge, Sarnia

2 Risks to be Re-evaluated in Q4
Lost deliverability due to abandoned wells (Endorsed as a Medium)
Panhandle Replacement (previously Detroit River Crossing)

Q4 Risk Summary

Quarter over quarter changes

4 Risks Mitigated in Q4
Parkway Plant C Power Turbine Failure impacting operational capability
London Lines - Replacement to address condition concerns
Corunna Compressor Station – High velocities induced vibration at the Crossflow header
Indirect Fired Heaters at stations in SW and SE Districts (All high-risk sites have been mitigated)

Quarterly Risk Update

Significant Risks						
Risk Name	Risk Owner	Current Residual Risk	Treatment Plan	Expected Residual Risk	Due Date	Quarterly Treatment Status
Parkway Plant C Power Turbine Failure impacting operational capability: Existing power turbine at Parkway C has sustained serious damage and has to be taken out of service. There is a risk of Parkway Compressor station not being able to supply volume of gas required if there are any other operational upsets	Peter Jurgeneit	Very High	Investment to purchase and install a new (refurbished) power turbine for Parkway Plant C.	Medium	2022	• Risk workshop completed in Q3 • Risk Endorsement completed in Q3 • Installation timeline for newly arrived turbine to be developed. Awaiting availability of Siemens representatives to assist with work. • Plant A maintenance scheduled for late Oct / early Nov following installation of turbine. • **Replacement power turbine installation complete**

Quarterly Risk Update

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Significant Risks						
Risk Name	Risk Owner	Current Residual Risk	Treatment Plan	Expected Residual Risk	Due Date	Quarterly Treatment Status
Corunna Compressor Station – rare worker safety event due to loss of containment	Wes Armstrong	Intolerable H&S Risk for Workers	Short-term Risk Treatment • Operations to lead on investigating potential operational adjustments (in place) Long-term Risk Treatment • See treatment plan for risk "Corunna Compressor Station - Aging compression units (K-701/2/3)"	Long-term plan expected to bring risk to Medium	2023 (Long-term)	Short-term Risk Treatment Plan • Changes already made to operators' rounds (to reduce time spent in compressor buildings) • Plan in progress for further proposed changes (depressurizing units for longer term outages, reducing time with units pressurized) • Quarterly Corunna compressor usage tracking ongoing Long-term Risk Treatment Plan • 20 km NPS 36 (TR7) pipeline approved by Capital Allocation Committee (CAC). LTC application **approved by OEB November 3, 2022** for ISD of 2023.
Corunna Compressor Station - Aging compression units (K-701/2/3)	Wes Armstrong	High	• Economic assessment completed for alternative options. Options such as compressors replacement (gas and electric driven), installing a high-pressure transmission line between Dawn and SCOR are being considered for the integrated storage system (Dawn to Corunna project).	This specific risk scenario is expected to be removed from RR once treatment plan is complete.	2023	• 20 km NPS 36 (TR7) pipeline approved by Capital Allocation Committee (CAC). LTC application **approved by OEB November 3, 2022** for ISD of 2023. • A comprehensive to review the reliability, availability and maintainability (RAM) risks at the site through a RAM study was **completed in 2022**, with support from external consultant that provided an understanding of site wide operational risks

Quarterly Risk Update

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Significant Risks						
Risk Name	Risk Owner	Current Residual Risk	Treatment Plan	Expected Residual Risk	Due Date	Quarterly Treatment Status
Indirect Fired Heaters at stations in SW and SE Districts (Glycol Leaks at Stations)	Dean Dalpe	High	Long Term Risk Treatment • All indirect fired heaters in Legacy UG have been site visited and risk assessed. A multi-year replacement plan has been developed. Short Term Risk Treatment • Current short-term mitigation plan is monitoring of fluid levels of Indirect Fired Heaters.	Medium	**2022** – All high-risk stations	• 20/50 replacements completed (some sites have multiple units) • **All high-risk heater replacements were commissioned by end of Q4 2022**
Overpressure of Low Pressure network	Murray Costello	High	• **Retrofitting stations to include an additional pressure control device (either one of full capacity relief, monitor regulator or slam-shut valve) at the existing station so that minimum code requirements are met** • **Rebuild network to IP including stations and provide each customer in network with a service regulator (with internal relief) at the customer meter set** • **Rebuild station to new engineering standard for LP stations**	Medium	2023	• Some treatment plans were implemented including LP station abandonment • **Implementation of risk treatment / action plans is underway** • **All High-risk stations have short term plans starting in 2023** • **2 stations that had no short-term plans at the time of July 14th director endorsement now have plans and have been prioritized for execution in 2023**

Quarterly Risk Update

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Significant Risks						
Risk Name	Risk Owner	Current Residual Risk	Treatment Plan	Expected Residual Risk	Due Date	Quarterly Treatment Status
London Lines	Steven Jelich	High	Long Term Risk Treatment • Replacement of the existing line with a single 3450kPa NPS 6 / 4 Short Term Risk Treatment • Maintain current operating pressure • Increase leak survey to three (3) time per year; spring, summer and fall • Increase inspection frequency to annual for all main line valves • Communication for landowners related to DoC concerns • Conduct pipeline marker field survey	Medium /Low	2022	• New pipeline is fully operational • **Existing line decommissioned December 2022**
Corunna Compressor Station – High velocities induced vibration at the Crossflow header	Wes Armstrong	Medium	Short-term Risk Treatment • Flow metering and vibration monitoring upstream of the crossflow header Long-term Risk Treatment • New piping designed with pressure control and protection provisions needed to safely manage multiple pipeline and header MOPs (Meter Run Replacement project)	This specific risk scenario is expected to be removed from RR once treatment plan is complete.	2022	Short-term Risk Treatment • Mitigations installed for operations to monitor flow velocity and vibration associated with the crossflow header. Long-term Risk Treatment • Meter Run Replacement Project scheduled for in-service in 2022 • Detailed risk assessment for Phase 2 has been completed. • **Project has been placed in service**

Quarterly Risk Update

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Significant Risks						
Risk Name	Risk Owner	Current Residual Risk	Treatment Plan	Expected Residual Risk	Due Date	Quarterly Treatment Status
Lost deliverability due to abandoned wells	Wes Armstrong	Medium	• Replace abandoned wells at Kimball and Dow Moore reservoirs.	Medium /Low	**2023**	• Continue to assess deliverability as the Kimball well is drilled to determine if an additional well is required. • **New residual risk in Q4 is Medium**
Panhandle Replacement (Previously known as Detroit River Crossing)	Wes Armstrong	High	• Three treatments were assessed- replace, abandon or install ILI facilities. • Replacement option was selected	Medium /Low	Proposed In-Service Date: 2024	• Ongoing negotiations with Energy Transfer Partners to work toward full mitigation plan • Integrity management is **evaluating** inspection **options** • **Risk re-evaluation workshop kicked off in Q4, second session scheduled Q1, 2023**

Quarterly Risk Update

Significant Risks						
Risk Name	Risk Owner	Current Residual Risk	Treatment Plan	Expected Residual Risk	Due Date	Quarterly Treatment Status
Obsolete MCCs and lack of spare parts	Wes Armstrong	High	• Replace MCCs to the new standards • Program to address obsolescence by 2026. • Site specific projects identified	Medium	2026	• Experiencing material delays and resource constraints • Aligning program with Obsolete Fire/Gas detection panel replacement program to optimize outage windows • Major Compressor sites at Dawn, Lobo, Bright and Parkway to be completed in 2026 • As units are replaced, spare inventories are generated

Quarterly Risk Update

ENBRIDGE
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Significant Risks						
Risk Name	Risk Owner	Current Residual Risk	Treatment Plan	Expected Residual Risk	Due Date	Quarterly Treatment Status
Obsolete Allen Bradley PLC control system at STO	Wes Armstrong	High	• Replace PLCs to the new standards • Program to address obsolescence by 2026. • Site specific projects identified	Medium	2026	• Lobo B installed and commissioned **on Dec 12, 2022** • Bright B design discussion **on hold until Q1 2023** • Experiencing material delays and resource constraints • As units are replaced, spare inventories are generated
Siemens valve controller	Peter Jurgeneit	High	• Program – 2 units per year. Start in 2020, target completion in 2025. • Spares inventory created as replaced. • Short-term risk treatment – A strategy to increase spare parts inventory is underway • We have now reached the point in time where the vendor will no longer support these valve controllers.	This specific risk scenario is expected to be removed from RR once treatment plan is complete	2025	• Parkway B – replacement controller shipped, and to be installed and commissioned in 2023 • Bright A1/A2 – installed **on Nov 18, 2022** • Lobo C & Parkway C – material on order in 2022, install in 2023

Quarterly Risk Update

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Significant Risks						
Risk Name	Risk Owner	Current Residual Risk	Treatment Plan	Expected Residual Risk	Due Date	Quarterly Treatment Status

Obsolete Fire/Gas detection panels	Peter Jurgeneit	High	• Replace Fire/Gas detection panel to the new standards to avoid a situation of unit unavailability impacting deliverability.
			• Site specific projects identified by year taking resources and criticality into consideration.
				Medium	2026	• **Dawn D and Parkway East are to be installed and commissioned in Q2/Q3 2023**
						• **Dawn E equipment will be ordered in 2023 with install/commissioning in 2024**
						• Control panel components impacted by the global chip shortage. Manufacturer is considering redesigning components to make use of another chip.
						  • **Equipment for Dawn D has either arrived or is in transit**
						  • **Impacts to Parkway East and Dawn E are not known at this time**
						• Aligning program with Obsolete MCCs and lack of spares program to optimize outage windows
						• Major Compressor sites at Dawn, Lobo, Bright and Parkway to be complete in 2026
						• As units are replaced, spare inventories are generated

Reliability of remote reciprocating compressor units at storage pool stations (Waubuno)	Wes Armstrong	High	Short Term Risk Treatment • Purchase gas on the spot market and review annual maintenance checks for leading indicators of compressor failure Long Term Risk Treatment • Replacement - Proposed to replace compression with 1.6 km of NPS 20 from Waubuno to TR7	Medium /Low	2025	• **Dawn to Corunna pipeline project was approved by the OEB in November 2022** • **TotEx Value Modelling has begun for Waubuno**

Quarterly Risk Update

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Significant Risks						
Risk Name	Risk Owner	Current Residual Risk	Treatment Plan	Expected Residual Risk	Due Date	Quarterly Treatment Status
Creek Crossing Exposures on Port Stanley Lateral	Steven Jelich	High	• Pipe replacement	Medium /Low	2024	• Treatment plan is captured in the 2023 – 2032 AMP • Budget has been approved for some preliminary works (Geotech, Drafting) to commence in 2023 • **Project management activities (Leave to Construct project) will begin in 2023** • **Construction is anticipated to commence in Q3 2024** • **Integrity Management to determine Risk Assessment approach pending outcome of St. Laurent.**
Barrie to Collingwood – Cumulative additions between 2018 and 2026.	Mark Maxwell	High	Long Term Risk Treatment • The recommended solution is pressure elevation of the entire pipeline. The other option was to elevate the pressure for a part of the pipeline which would be used as a contingency plan if costs exceed budget. Short Term Risk Treatment • Keep the Barrie and Collingwood line (NPS 8) on Network Analysis watch list to monitor future demand.	This specific risk scenario is expected to be removed from RR once treatment plan is complete	**2024**	• **Capital investment to complete pressure elevation deferred from 2023 to 2024 due to capital constraints** • **DOE and Engineering have agreed to elevate the line to 420 PSI in 2023, followed by full elevation to 500 PSI in 2024** • **Risk re-evaluation to be scheduled for Q1, 2023**

Quarterly Risk Update

Significant Risks						
Risk Name	Risk Owner	Current Residual Risk	Treatment Plan	Expected Residual Risk	Due Date	Quarterly Treatment Status
Inside Regulators	Tracey Teed Martin	Medium	• Consider relocating indoor regulators into an external regulator room or relocate outdoors • Operations project team reviewing sites using regional approach; prioritizing below grade service entry without Excess Flow Valve (EFV)	Medium /Low	2025	• Population of concern is now **511** locations with no EFVs • Project team identified locations with no EFV and below grade entry for priority focus and currently working with Risk Services to initiate formal risk evaluation on review of above ground shutoffs. • Project team working to **execute and to continue to identify other ways** to prioritize work, including VSM overlap, municipal reconstruction and regional maintenance • Updated GIS records for annual valve inspection and updated service classification to critical to trigger 3rd party observation

Quarterly Risk Update

Emerging Risks		
Emerging Risk Name	Potential Impact	Quarterly Status
Fisher 627 Regulator Bolts Fracture due to Manufacturing Defects	• Gas escape typically at set point of regulator leading to potential evacuation, fire and explosion. • Potential for customer supply loss (system stations)	• Risk workshop conducted; risk is Medium (Health & Safety) • Risk Endorsement completed December 13, 2022 • Risk treatment plan (Corrective Action Plan) is being implemented
Vidal St Walking Bridge, Sarnia	• NPS 12 420kPa gas main that runs over the CN railway tracks that is within a walking bridge operated by the city of Sarnia. • Isolation of this crossing could lead to a large customer outage as there are no valves on either side of the bridge. In addition, the location of the pipe creates challenges for access, repair, and maintenance.	• Initial discussions complete. Compiling additional information to inform risk workshop is underway.

Quarterly Risk Update

Risks to be Re-Evaluated		
Emerging Risk Name	Potential Impact	Quarterly Status
Lost deliverability due to abandoned wells	• Total Financial impact of >$100k and ≤$1M multiple times in the last ten years resulting in a Medium Risk L6C3	• Continue to assess deliverability as the Kimball well is drilled to determine if an additional well is required. • New residual risk in Q4 is Medium
Panhandle Replacement (previously Detroit River Crossing)	• A potential loss of containment and liquids release in the Detroit River could lead to Reputational, Financial, Environmental, Operational and Regulatory Consequences.	• Ongoing negotiations with Energy Transfer Partners to work toward full mitigation plan • Integrity management is evaluating inspection options • Risk re-evaluation workshop kicked off in Q4, second session scheduled Q1, 2023

Compliance Management Update: Legal and Regulatory Changes

Requirement	Change/Proposed Change	Impact/Potential Impact	Action/Change Owner	Due Date
EAWM Framework Standard	March 2022 - Enterprise AM released draft of new EAWM FS. Provided to GDS and other BU's for comments.	• 2022 - FS is in draft status • 2023 - FS implementation impacts to be reviewed	Bob Wellington	**Q2** 2023

YTD Assurance Plan Progress

Assurance Type	Date	Assurance Activity Description	Findings	Management Action Plans	Status
• Audit	• Previously planned for Q3/Q4 • No longer required in 2022	-	-	-	• 2022 Jacob's Audit no longer required as existing maturity assessments deemed adequate at this time
• Audit	• No longer required in 2022	-	-	-	• MP-01 Internal Audit no longer required in 2022 • Tied to Jacob's audit

Resource Adequacy Confirmation

Resource Type	Updates/Changes	Mitigation Plan
Human Resources	• No Updates	• Not Required
Capability Management	• No Updates	• Not Required
Capacity	• No updates	• Not Required
Tools & Technology	• No updates	• Not Required
Budget	• No updates	• Not Required

2023 Priorities

2023 TOM Improvements

**Scope and deliverables to be determined*

AM Strategy & Planning

- Deliver 2024 AMP Addendum and initiate 25-34 AMP revision
- Successfully execute AIPM Objectives
- Enhance AM Tools to support ET Investments and address GHG considerations
- Advance IRP integration into AIPM process

AM Decision-Making

- Increase use of Value Framework Assessment and Value-based decision-making
- Improved estimation & forecasting and expand capital metrics and tracking
- Continue development of TotEx Value Models

Asset Information

- Improve data and record quality (ex Maximo, SAP-PM, Investment Data)

Risk & Review

- MOC for changes to RMFS (7x7, Potential Hazards)
- Improve guidance for conditionally tolerable risks

2023 Draft Workplan Refresh

EGD – 2023 Core Capital	
Base Capital	$700.1M
ICM Capital	$21.5M
Total Core	$721.6M

UG – 2023 Core Capital	
Base Capital	$774.9M
Total Core	$774.9M

EGI – 2023 Core Capital	
Base Capital	$1,475M
ICM Capital	$21.5M
Total Core	$1,496.5M

Just how big is the Enbridge Gas 2023 workplan?

The Enbridge Gas workplan is forecasting to execute on $1.5B in 2023.

The workplan consists of 13 distinct Asset Classes:

Distribution

1. Customer Connections
2. Distribution Pipe
3. Distribution Stations
4. Growth
5. Utilization

Storage

6. Compression Stations
7. Liquified Natural Gas (LNG)
8. Transmission Pipe and Underground Storage

Non-Gas Carrying

9. Real Estate & Workplan Services (REWS)
10. Technology & Information Services (TIS)
11. Fleet & Equipment

Finance

12. Corporate Capital
13. EA Fixed Overheads

2023 Draft Workplan Refresh

How is the 2023 Workplan created?

- The 2023-2032 Capital Plan forms the basis for the 2023 Workplan.
- Asset Management uses the data from Copperleaf to forecast the 2023 capital requested to maintain both Legacy Union Gas (LUG) and Legacy Enbridge Gas (LEG) assets.
- The 2023 forecasts are inputted from our Investments Owners across both rate zones, all regions, many execution groups, and stakeholders within the business.
- Each Asset Class has an Asset Class Manager who vets and reviews the investments and the forecasts within their portfolio. The Asset Class Manager ensures the forecasted capital is sufficient to address the asset strategies documented in our Asset Management Plan.
- The Asset Class Managers, Finance Department, and Asset Management Governance work together to ensure the forecasted workplan is defendable and supports both regulatory and Enbridge's financial targets
- Throughout 2023 Asset Management will support the execution of the 2023 Workplan, the executed investments will help maintain and grow our assets to safely and reliably deliver natural gas to our customers.

2023 Draft Workplan Refresh

EGD Rate Zone

	2023 Approved November Workplan
EGD	**721,537,631**
EGD - Core	**700,079,431**
Customer Connections	134,700,191
Customer Connections TCS	500,006
Distribution Pipe	62,074,683
Distribution Stations	38,962,775
Growth	14,097,225
Utilization	66,979,320
Compression Stations	114,521,739
Transmission Pipe & Underground Storage	11,983,267
Fleet & Equipment	9,022,154
Real Estate & Workplace Services	47,510,800
TIS	40,399,915
EA Fixed O/H	16,976,806
Corporate	142,350,549
EGD - ICM Project	**21,458,200**
Distribution Pipe	21,458,200
Grand Total	**721,537,631**

Workplan Highlights

- The **Customer Connections** and **Customer Connections TCS** are forecasting similar to 2022 actuals.
- The Distribution Stations asset class will begin executing on **GTAW Parkway Gate Station Rebuild** and **St John Sideroad Feeder**
- Work planned to address risk at **Corunna Compressor Station**
- Real Estate & Workplace Services is forecasting spend for **Station B New Building** and **Ottawa New Build.**
- **NPS 20 Lake Shore Replacement (Cherry to Bathurst)** is the only ICM spend identified in 2023.

2023 Draft Workplan Refresh

UG Rate Zone

	2023 Approved November Workplan
UG	**774,866,924**
UG - Core	**774,866,924**
Customer Connections	69,422,033
Customer Connections TCS	1,500,000
Distribution Pipe	124,458,248
Distribution Stations	37,484,844
Growth	41,692,767
Utilization	51,697,217
Compression Stations	51,051,843
LNG	882,719
Transmission Pipe & Underground Storage	213,009,661
Fleet & Equipment	8,562,604
Real Estate & Workplace Services	10,563,600
TIS	8,080,140
EA Fixed O/H	5,540,608
Corporate	150,920,640
Grand Total	**774,866,924**

Workplan Highlights

- Distribution Pipe Integrity spend includes **Independent Asset Integrity Review, Owen Sound Section 5** and **NPS 8 Stratford.**
- Growth includes work for the **NextStar Energy (Stellantis) EV Battery Manufacturing Plant** and **Hensall Trans Rebuild.**
- **Panhandle Regional Expansion Project** continuing execution in 2023 captured in the Transmission Pipe & Underground Storage asset class

TotEx Update

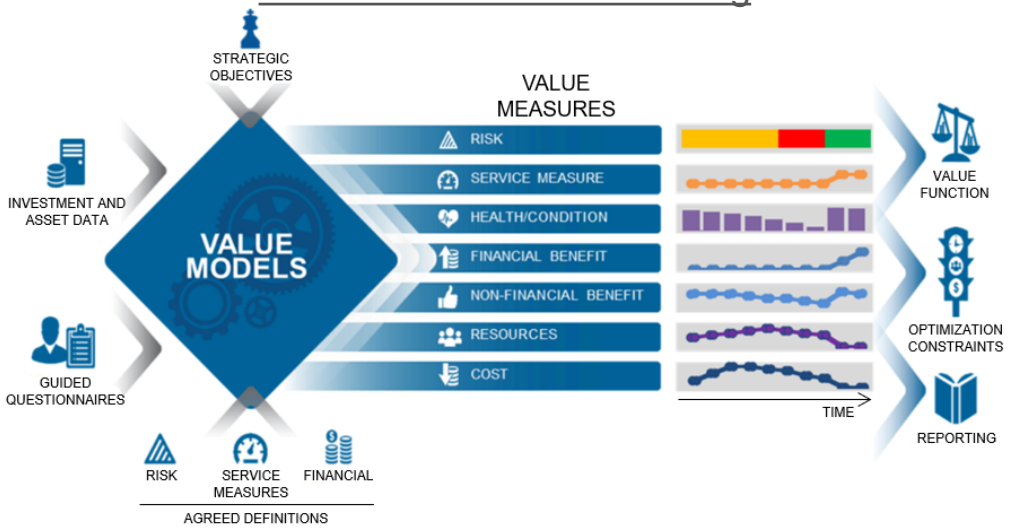
TotEx Value Models - Recap

Compliment existing processes and strengthen decision basis

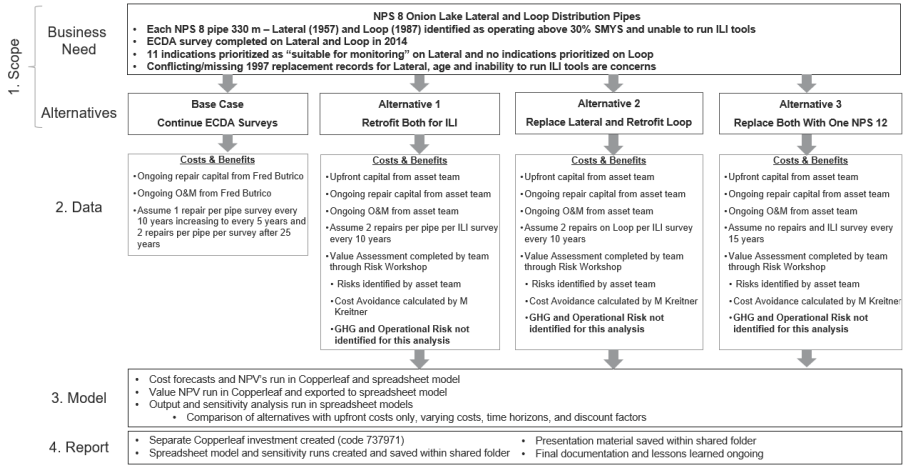
- Applying TotEx Value Models within AIPM
  - Follow established AIPM workflows simplified into 4 overall stages – Scope, Data, Model, and Report
  - Define thresholds for use TBD - ex. capital and scope
  - Follow Copperleaf procedure for investment analysis with included requirement for multiple alternatives, inclusion of ongoing capital and O&M, and a value assessment

- Phase 2 Implementation:
  - Pilot on select asset classes to inform appropriate method, data, models, and tools
  - Onion Lake distribution pipe analysis complete and communication of results and learnings ongoing
  - Templates and methods developed being used and refined as Dawn C and Waubuno analysis progresses

Value Based Decision Making



TotEx Value Model Roadmap

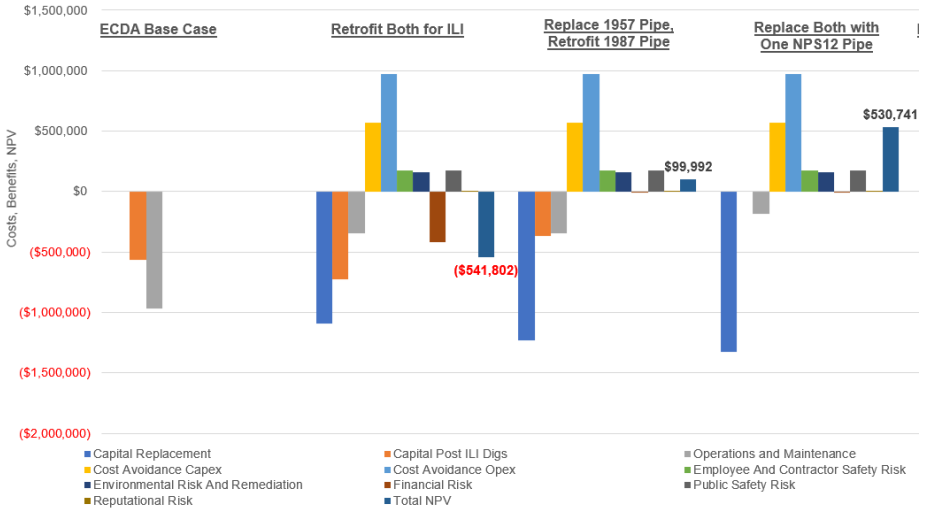


Onion Lake Analysis – Results

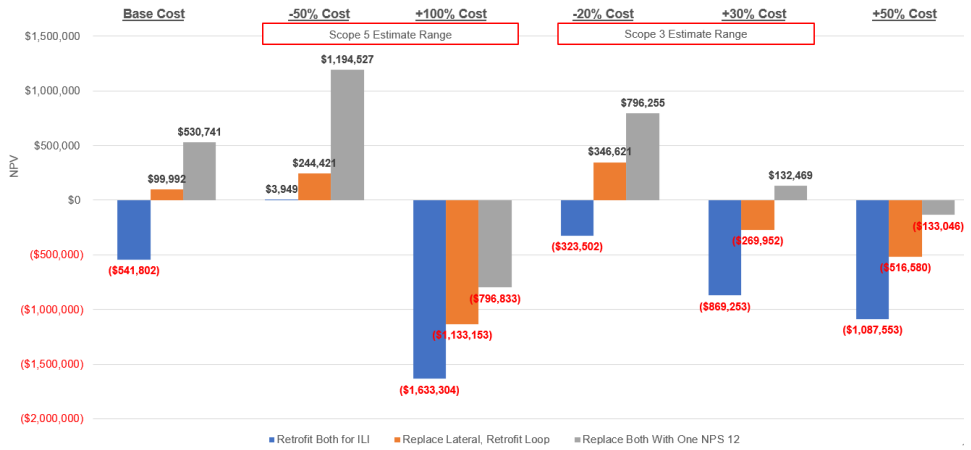
Distribution Pipe Pilot

- Costs:
  - Upfront costs account for bulk of discounted costs in analysis – 50 to 90% (retrofit to replace alternative)
  - Uncertainty in scoping cost estimate will potentially influence future value as cost estimates mature
- Assumptions:
  - Increasing discount rate has minimal effect on upfront costs and greatest negative impact to cost avoidance – $150k to 400k
- Benefits:
  - Cost avoidance account for bulk of calculated value in analysis – 50 to 70% (retrofit to replace alternative)
  - Sensitivity analysis on operational risk showed little impact until consequence level 6

NPV Comparison of Alternatives (40 yrs)



Sensitivity Analysis of Cost Estimate



Onion Lake Analysis – Learnings

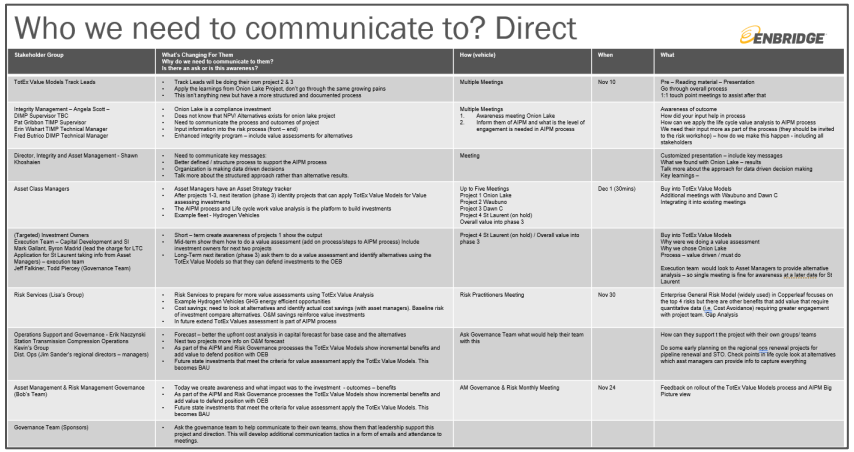
Method, data, models, and tools development ongoing

- Method:
  - Good definition of scope, value drivers, and base case is critical for model
  - Initial communication and collaboration ensures stakeholder engagement
  - Continuous process – sharing and updating as we work each investment
- Data:
  - Collection is the most time consuming but also the most important step
  - Documenting data gaps and assumptions to defend choice of alternative
- Models:
  - Detailed ongoing costs for base and alternatives necessary for cost avoidance calculations
  - Use quantitative data vs qualitative inputs for value assessments when possible to assess risk benefits
- Tools:
  - Templates to aid investment analysis for scope, model, and report stages developed
  - NPV calculation using spreadsheets to assess financial cost & benefits, perform sensitivity analysis and QA results

TotEx Value Models Checklist Template

Task Name	Duration	Start	Finish	Predecessors	Resource Names
TotEx Value Models					
Generic Project (Investment Name)					
1. Scope: Determine investment purpose, alternatives, value drivers, and stakeholder involvement					
TotEx Value Models Tasks					
Define investment scope, business need, and value drivers					
Determine investment base case & alternatives					
Define stakeholder roles & responsibilities					
Develop TotEx Value Models plan, timeline, & milestones					
TotEx Value Models Deliverables					
Gannt chart developed					
RAPID chart developed					
Copperleaf investment initiated					
2. Data: Collect data requirements and define boundaries and assumptions					
TotEx Value Models Tasks					
TotEx Value Models Deliverables					
3. Model: Model capital, O&M, and value for each alternative and analyze outputs and sensitivities					
TotEx Value Models Tasks					
TotEx Value Models Deliverables					
4. Report: Record and communicate results, monitor performance, and identify continuous improvements					
TotEx Value Models Tasks					
TotEx Value Models Deliverables					

Communication Plan Template



Who we need to communicate to? Direct

Stakeholder Group	What's Changing For Them Why do we need to communicate to them? Is there an ask or is this awareness?	How (vehicle)	When	What
TotEx Value Models Track Leads	• Track Leads will be doing their own project 2 & 3 • Apply the learnings from Onion Lake Project, don't go through the same growing pains • This isn't anything new but have a more structured and documented process	Multiple Meetings	Nov 10	Pre – Reading material – Presentation Go through overall process 1:1 touch point meetings to assist after that
Integrity Management – Angela Scott – DIMP Supervisor TBC Pat Gribbon TIMP Supervisor Erin Vikhart TIMP Technical Manager Fred Bohlco DIMP Technical Manager	• Onion Lake is a compliance investment • Does not know that NPV/ Alternatives exists for onion lake project • Need to communicate the process and outcomes of project • Input information into the risk process (front – end) • Enhanced integrity program – include value assessments for alternatives	Multiple Meetings 1. Awareness meeting Onion Lake 2. Inform them of AIPM and what is the level of engagement is needed in AIPM process		Awareness of outcome How did your input help in process How can we apply the life cycle value analysis to AIPM process We need their input more as part of the process (they should be invited to this risk workshop) – how do we make this happen – including all stakeholders
Director, Integrity and Asset Management - Shawn Khoshaein	• Need to communicate key messages • Better defined / structure process to support the AIPM process • Organization is making data driven decisions • Talk more about the structured approach rather than alternative results.	Meeting		Customized presentation – include key messages What we found with Onion Lake – results Talk more about the approach for data driven decision making Key learnings –
Asset Class Managers	• Asset Managers have an Asset Strategy tracker • After projects 1-3, next iteration (phase 3) identify projects that can apply TotEx Value Models for Value assessing investments • The AIPM process and Life cycle work value analysis is the platform to build investments • Example fleet - Hydrogen Vehicles	Up to Five Meetings Project 1 Onion Lake Project 2 Waubuno Project 3 Dawn C Project 4 St Laurent (on hold) Overall value into phase 3	Dec 1 (30mins)	Buy into TotEx Value Models Additional meetings with Waubuno and Dawn C Integrating it into existing meetings
(Targeted) Investment Owners Execution Team – Capital Development and SI Mark Gallant, Byron Mashtil (lead the charge for LTC Application for St Laurent taking info from Asset Managers) – execution team Jeff Falkner, Todd Piercey (Governance Team)	• Short – term create awareness of projects 1 show the output • Mid-term show them how to do a value assessment (add on process/steps to AIPM process) include investment owners for next two projects • Long-Term next iteration (phase 3) ask them to do a value assessment and identify alternatives using the TotEx Value Models so that they can defend investments to the OEB	Project 4 St Laurent (on hold) / Overall value into phase 3		Buy into TotEx Value Models Why were we doing a value assessment Why we chose Onion Lake Process – value driven / must do Execution team: would look to Asset Managers to provide alternative analysis – so single meeting is fine for awareness at a later date for St Laurent
Risk Services (Lisa's Group)	• Risk Services to prepare for more value assessments using TotEx Value Analysis • Example Hydrogen Vehicles GHG energy efficient opportunities • Cost savings need to look at alternatives and identify actual savings (with asset managers). Baseline risk of investment, Qualitative vs. Quantitative savings across value investments • In future extend TotEx Values assessment is part of AIPM process	Risk Practitioners Meeting	Nov 30	Enterprise General Risk Model (widely used) in Copperleaf focuses on the top 4 risks but there are other benefits that add value that require quantitative data (i.e. Cost Avoidance) requiring greater engagement with project team. Gap Analysis
Operations Support and Governance - Erik Naszynski Station Transmission Compression Operations Kevin's Group Dist. Ops (Jim Sander's regional directors – managers)	• Forecast – better the upfront cost analysis in capital forecast for base case and the alternatives • Next two projects more info on O&M forecast • As part of the AIPM and Risk Governance processes the TotEx Value Models show incremental benefits and add value to defend position with OEB • Future state investments that meet the criteria for value assessment apply the TotEx Value Models. This becomes BAU	Ask Governance Team what would help their team with this		How can they support t the project with their own groups/ teams Do some early planning on the regional ops renewal projects for pipeline renewal and STO. Check points in life cycle look at alternatives which east managers can provide info to capture everything
Asset Management & Risk Management Governance (Bob's Team)	• Today we create awareness and what impact was to the investment – outcomes – benefits • As part of the AIPM and Risk Governance processes the TotEx Value Models show incremental benefits and add value to defend position with OEB • Future state investments that meet the criteria for value assessment apply the TotEx Value Models. This becomes BAU	AM Governance & Risk Monthly Meeting	Nov 24	Feedback on rollout of the TotEx Value Models process and AIPM Big Picture view
Governance Team (Sponsors)	• Ask the governance team to help communicate to their own teams, show them that leadership support this project and direction. This will develop additional communication tactics in a form of emails and attendance to meetings.			

Key Changes to Investment Evaluation Approach

ENBRIDGE Life Takes Energy

Today

1. Scope:
   1. Define scope and business need
   2. Define base case and alternatives
   3. Follow AIPM schedule
2. Data:
   1. Collect asset and financial data for upfront and ongoing costs
   2. Do a value assessment if required (by AIPM definition)
3. Model
   1. Model NPV using upfront costs and value assessment data (if available) using Copperleaf and spreadsheets
   2. Compare alternative case NPV's with any additional non-quantitative information to determine best option
4. Report
   1. Documentation within Copperleaf
   2. Communication with stakeholders as needed

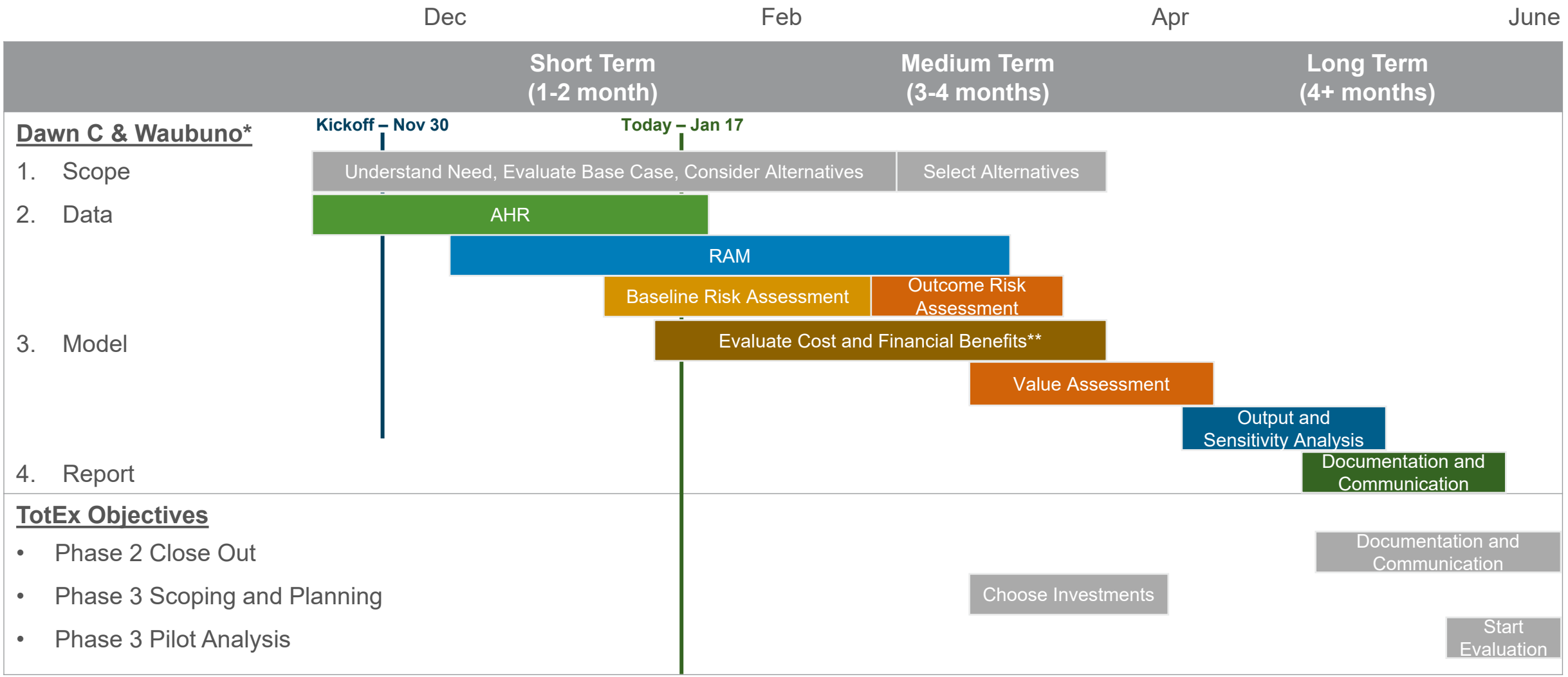
Tomorrow

1. Scope
   1. Define scope, business need, **and value drivers**
   2. Determine base case and alternatives
   3. **Develop stakeholder and timeline plan**
   4. **Track issues and actions**
2. Data
   1. Collect asset and financial data for upfront and ongoing costs
   2. **Perform a value assessment using quantitative methods whenever possible**
   3. **Identify and record data gaps, assumptions, and learnings**
3. Model
   1. Model NPV using upfront costs **ongoing costs, and value assessment data** using Copperleaf and spreadsheets
   2. **Perform output and sensitivity analysis on NPV models**
   3. Compare alternative case NPV's with any additional non-quantitative information to determine best option
4. Report
   1. Documentation within Copperleaf and **externally**
   2. **Develop communication plan for stakeholders**
   3. **Develop continuous improvement plan based on results**

For investments that meet criteria, more focus on comparative analysis and documentation of decision basis

Phase 2 Analysis in Progress

Continuously improve methods, models, and tools as necessary



* *Dawn C and Waubuno tracks have similar evaluation timing; estimated regulatory submission for Waubuno Q4 2023 / Q1 2024 and Dawn C in 2024*

** *Cost and financial data previously collected, update as alternatives selected*

IRP Update

Key Focus of the IRP Team

1. Advancing projects through the IRP Assessment Process
2. Implementing 2 Pilot projects in 2023
3. Regional Stakeholder Engagement
4. Enhancing the DCF+ Economic Evaluation test
5. Additional items beyond key focus areas

IRP Assessment Status Update

- IRP Assessment process has us reviewing the projects in the AMP to determine if their needs can be met by an IRP Alternative.
- Currently working through the Technical Evaluations of the 800+ projects that have passed binary screening, close to 65% complete
- Working with New Builder Relations in an attempt to exempt Customer Connections
- Growth is the most complex to assess as;
  - CNG can defer projects indefinitely, but not a solution
  - The abilities of Enhanced Targeted Energy Efficiency are not known at this time
  - Working to create bookends to guide us to the most opportunistic investments for prioritization and success.
- Will file an updated Appendix B in the interrogatory process of Rebasing

Internal Stakeholder Engagements

Internal engagement sessions have been held in 6 of the 7 Operating Regions as of December 14th

- Refresher on IRP 101
- Highlighted number of projects in the region as listed in the AMP and where we are with the screening process

Regional sessions have been booked for late January, February, and early March

- Webinar format open to the public participants that have registered on the Regional Planning / IRP Web site
- Internal invites have been sent

IRP Pilot Update

Pilot Areas

1) Parry Sound
2) Southern Lake Huron

Key Pilot Objectives

- Develop an understanding of how to design, deploy and evaluate an Enhanced Targeted Energy Efficiency (ETEE) and Demand Response(DR) program.
- Develop the ability and data to understand how DR and ETEE measures impact peak hour demands.

Status

- Working to ensure granular reads can be obtained in the pilot areas – installing ERTs
- Further developing the execution plan for actioning in 2023

Health Check: MP-01 Asset Management

Date: January 17, 2022
Accountable Person: Katie Hooper
Lead: Bob Wellington

MP Quarterly Accomplishments & Key Deliverables

- Finalized the 2023 Draft Workplan within budgetary targets
- Continued management of 2022 capital budget within 3.8%
- Received LTC from OEB for Dawn to Corunna Pipeline
- Worked with other business units and Enterprise Asset Management on Value Framework updates; Continued to incorporate improvements

CER-Regulated Asset Activity

Panhandle Replacement (aka Ojibway or Detroit River Crossing)	• No contact with Energy Transfer Partners Q4 2022, plan to meet in Q1 2023. • Re-evaluation of Risk Assessment kicked off in December, will continue through January.

2022 YTD Objectives and Metrics

Target End Date	% Complete	Annual Objective	Status
Jun-22	100%	2023-2032 AMP	Complete
-	-	Completion of Asset Management Maturity Assessment - No longer required for 2022	N/A
Sept-22	100%	Value Based Decision Making Improvements (previously titled Roadmap for Value Framework Improvements)	Complete
Apr-22	100%	Roadmap for Life Cycle Value	Complete
May-23	45%	Execute Phase 2 of TotEx Value Models (Life Cycle Value) Roadmap	On track
Nov-22	100%	Develop Multiyear Timeline for AMP	Complete

Target	Actual YTD	Metrics	Status
603.1M	**693.7M	2022 Actual	Off Plan
734.9M	**679.6M	2022 Actual	Off Plan
544M	648M*	In-Service Capital Budget (UGL RZ) **8+4 Forecast*	Off Plan
732M	680M*	In-Service Capital Budget (EGD RZ) **8+4 Forecast*	On track
369.8M	**290.3M	Core Capital Maintenance (EGI) **9+3 Forecast*	Off Plan
70%	47%	Failure Code Reporting – Distribution *Expected improvements from AWS Phase 2 were not realized. A recommendation to remain status quo with back-end corrections has been made to Data Governance Council.*	At Risk

Regulatory Compliance Update &/or Legal & Regulatory Changes

Requirement /Issue	Impact/Action
March 2022- Enterprise Asset & Work Management (EAWM) has released draft Framework Standard (FS)	GDS review with affected stakeholders underway.

Resource Adequacy Confirmation/TMR Ask

- No TMR Ask

MP-01 Objectives and Progress Update

Objectives and Progress Update

TOM*	Objective	Key Highlights/Accomplishments for Q4	Planned for Q1 2023	On track (Yes/No)
Strategy & Planning	Asset Management Program (MP-01)	• MP-01 Program documentation (2022 Revision) complete • Draft AIPM processes for inclusion of IRP	• Finalize of measures of success for MP-01	Yes
	Integrated Asset Management Plan	• AMP filed with Rebasing application • Development of timeline for future AMP's and or addendums	• Ongoing Regulatory/Rebasing support including the filing of IR responses	Yes
	Copperleaf/System Enhancements	• Finance Training Content Delivered	• Continued support in updating Copperleaf	Yes
Decision Making	Support Regulatory Process	• Support Regulatory and Finance for rebasing application	• Ongoing Regulatory/Rebasing support including the filing of IR responses • Ongoing integration of IRP and AM Processes	Yes
	Operationalize the Asset Plan	• No activity	• Bi-annual status update on remaining recommendations	Yes

*TOM – Target Operating Model

Objectives and Progress Update

TOM*	Objective	Key Highlights/Accomplishments for Q4	Planned for Q1 2023	On track (Yes/No)
Organization & People	OCM & General Asset Management Awareness	• Complete Financial acumen training for STCO team. • Implement process and procedures for New User copperleaf training	• Continuous improvement opportunities to support business • Review gaps in training for existing users and develop plan to close training gaps	Yes
	Asset Management Roles/Accountabilities Development	• No activity	• No activity	Yes

*TOM – Target Operating Model

Objectives and Progress Update

TOM*	Objective	Key Highlights/Accomplishments for Q4	Planned for Q1 2023	On track (Yes/No)
Life Cycle Mgmt	Commodity-Carrying Assets Life Cycle Strategies	• Support for the completion of IR responses for PREP • Assigned and kicked off Totex Value Models. • AMP Appendix B (IRP) filed with Rebasing application • 2023 Budget Refresh support	• Revise AMP Appendix B (IRP) and file with OEB. • Finalize IRP and AIPM process and get proper buy-in to complete. • Continue data gathering process and refinement of decision models from Distribution Pipe projects. • Continued development of value models for LCV opportunity • Finalize 2023 Workplan • Support 2024 Budget process	Yes
	Non-Commodity Carrying Assets Life Cycle Strategies	• 2023 Budget Refresh support	• Finalize 2023 Workplan • Support 2024 Budget process	Yes
	Predictive Analysis	• Completion of SDIMP risk model development for pilot wells by Integral Engineering. Review of draft results from Integral Engineering underway. • SDIMP data from WellView copied into PiMSlider-SDIMP data verification within PiMSlider underway. • FIMP data model creation complete and data loaded to model. • Customized views created for better visualization. Hierarchy created for facilities, stations, and piping. • API 581 Implementation testing with current data. • QA with SPSS model.	• Perform internal review and sensitivity study of SDIMP risk model provided by Integral Engineering. • Finalize SDIMP risk model threats and consequence models. • Begin data model development and implementation of SDIMP risk model within PiMSlider. • Configure Corrosion Loop functionality with ATP. • Performance improvements in PiMSlider (ATP). i.e., DB configuration • Project/extrapolate damage factors in the future for inspection-based planning. • Migrate FIMP to PROD with testing.	Yes

*TOM – Target Operating Model

Objectives and Progress Update

TOM*	Objective	Key Highlights/Accomplishments for Q4	Planned for Q1 2023	On track (Yes/No)
Asset Information	Asset Information Strategy	• First Data set post AWS go live incorporated to dashboard • Completed 2016-2020 Historical Failure code classification • Created Data Governance onboard training for GDS asset working group/ integrity • Created strategy for Data Governance for Integrity/ Started strategy for Asset Management	• AWS phase 3 design for distribution station assets to EAM standards/ retire from SAP-PM • Collibra templates updated to Azure as part of AWS • Data Governance onboard training for all staff in Integrity who work with data and for GDS Asset Data Governance working group • Endorsement of Asset Data Governance Strategies • Review integrity system against data governance conformance template (on going post Q1)	Yes
	Maintain GDS Systems	• ProjectWise – Maximo Integration design/build/test completed by implementation on hold • Record Quality Management tracking system implemented • Develop Asset Information Roadmap BRSD • AWS 3 – Pre-design workshops completed SAP PM Distribution Operations retirement	• Develop reporting for Record Quality Management tracking system • Develop Asset Information Roadmap BRSD • AWS 3 – Design workshops SAP PM Distribution Operations retirement	Yes

*TOM – Target Operating Model

Objectives and Progress Update

TOM*	Objective	Key Highlights/Accomplishments for Q4	Planned for Q1 2023	On track (Yes/No)
Risk & Review	Value Framework Improvements for Decision Making	• Provided feedback to EAM on Value Assessment Standard and Guidelines • Working with Asset Intelligence to build dashboards for proactive analysis and reporting of investment portfolio	• Continue to work on Value Framework improvements • Continue to work on dashboards with Asset Intelligence	Yes
	Risk Standards and Processes	• Completed all scheduled training sessions for the PHA Standard • Completed Phase 1 training of HIRA Procedure for MP administrators and IMS supports • Enterprise S&R published the revised Risk Management Framework Standard & Enbridge Standard Operational Risk Matrix	• Conduct additional PHA Standard trainings for those who were unable to attend training in Q4 • Conduct Phase 2 training on HIRA procedure with risk management 101 for MP leads • Evaluate the impact of the revised Risk Management Framework Standard to the business and develop MOC plan • Develop plan on incorporating “Potential Hazard” in risk management practice	Yes
	EnCompass Implementation	• Data migration to EnCompass risk module and further work with Enterprise team • Completed development of change management plan • Completed development of Basic Navigation training and Risk Treatment owner training	• Planning for Q1 implementation • Awareness, Communication and roll out of basic navigation and risk treatment owner training to affected stakeholders	Yes

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 103

For 2023 and 2024, to advise as to the revenue requirement associated with the RNG projects, and whether the associated revenues are included in the budgeted revenue forecast.

Response:

Please see Attachment 1. Confirmed, the associated revenues are included in the budgeted revenue forecast.

RNG Revenue Requirement

Line No.	Particulars ($ millions)	2023	2024
		(a)	(b)
	Rate Base Investment		
1	Average Investment (1)	6.3	22.6
	Revenue Requirement Calculation:		
	Operating Expenses:		
2	Depreciation Expense (2)	0.2	1.0
3	Total Operating Expenses	0.2	1.0
4	Required Return (3)	0.4	1.3
5	Total Operating Expense and Return	0.5	2.3
	Income Taxes:		
6	Income Taxes - Equity Return	0.1	0.3
7	Income Taxes - Utility Timing Differences (4)	(0.2)	(0.8)
8	Total Income Taxes	(0.2)	(0.5)
9	Total Revenue Requirement	0.4	1.8
10	RNG Revenue (5)	1.5	6.9
11	Net Revenue Requirement	(1.1)	(5.1)

Notes:

(1) Exhibit 2, Tab 2, Schedule 1, Attachment 8, page 1, line 1, updated July 6, 2023, for 2024 Gross PPE and page 6, line 1 for 2024 Accumulated Depreciation.
Exhibit 2, Tab 2, Schedule 1, Attachment 7, page 1, line 1 and line 12, updated July 6, 2023, for 2023 Gross PPE and page 9, line 1 and line 10 for 2023 Accumulated Depreciation.

(2) Exhibit 2, Tab 2, Schedule 1, Attachment 8, page 6, line 1, updated July 6, 2023, for 2024 Depreciation expense
Exhibit 2, Tab 2, Schedule 1, Attachment 7, page 9, line 1 and line 10, updated July 6, 2023, for 2023 Depreciation Expense

(3) The required return for 2024 assumes a capital structure of 62% debt at 4.17% and 38% common equity at the 2022 OEB formula return of 8.66% whereas 2023 assumes a capital structure of 64% debt at 4.18% and 36% common equity at the 2022 OEB-approved return of 8.66%. The annual required return calculation for 2024 is as follows:

Average Investment x 62% x 4.17% plus Average Investment x 38% x 8.66%

(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(5) Exhibit 3, Tab 4, Schedule 1, Attachment 1, page 3, line 16, updated March 8, 2023.
Exhibit 3, Tab 4, Schedule 1, Attachment 1, page 3 , line 17, updated March 8, 2023.

ENBRIDGE GAS INC.

Answer to Undertaking from
Canadian Manufacturers & Exporters (CME)

Undertaking

Tr: 131

To produce a similar analysis or table for the Panhandle project at Exhibit 2, Tab 5, Schedule 4, Attachment 2, showing a levelized approach for the Dawn-Corunna project, from 2023 to 2028, for illustrative purposes.

Response:

Please see Attachment 1.

2023 to 2028 Dawn to Corunna

Line No.	Particulars ($ millions)	Revenue Requirement 2021	2022	2023	2024	2025	2026	2027	2028	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Rate Base Investment									
1	Capital Expenditures	0.5	40.0	301.7	18.9	-	-	-	-	
2	Cumulative Capital Expenditures	0.5	40.5	342.2	361.1	361.1	361.1	361.1	361.1	
3	Average Investment	-	-	66.9	343.0	344.4	335.5	326.6	317.7	
	Revenue Requirement Calculation:									
	Operating Expenses:									
4	Depreciation Expense (1)			3.4	8.9	8.9	8.9	8.9	8.9	8.0
5	Property Taxes			0.2	0.6	0.4	0.4	0.4	0.4	0.4
6	Total Operating Expenses			3.6	9.5	9.3	9.3	9.3	9.3	8.4
7	Required Return (2)			3.9	20.1	20.2	19.7	19.2	18.7	17.0
8	Total Operating Expense and Return			7.5	29.7	29.5	29.0	28.5	28.0	25.4
	Income Taxes:									
9	Income Taxes - Equity Return (3)			0.8	4.1	4.1	4.0	3.9	3.8	3.4
10	Income Taxes - Utility Timing Differences (4)			(38.8)	(11.3)	(5.4)	(3.8)	(2.6)	(1.7)	(10.6)
11	Total Income Taxes			(38.1)	(7.2)	(1.3)	0.2	1.3	2.1	(7.2)
12	Total Revenue Requirement			(30.6)	22.5	28.3	29.2	29.8	30.1	18.2

Notes:

(1) 2024 Depreciation expense at 2024 Proposed depreciation rates, 2023 depreciation expense based on current depreciation rates

(2) The required return for 2024 assumes a capital structure of 62% debt at 4.17% and 38% common equity at the 2022 Board Formula return of 8.66% whereas 2023 assumes a capital structure of 64% debt at 4.18% and 36% common equity at the 2022 board approved return of 8.66% The annual required return calculation for 2024 is as follows:
Average Investment (row 3) * 62% * 4.17% plus Average Investment (row 3) * 38% * 8.66%

(3) Taxes related to the equity component of the return at a tax rate of 26.5%.

(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction (inclusive of accelerated CCA) in arriving at taxable income exceeds the provision of book depreciation in the year.

ENBRIDGE GAS INC.

Answer to Undertaking from
Canadian Manufacturers & Exporters (CME)

Undertaking

Tr: 132

To provide what the level of in-service additions are for each of the planned near term.

Response:

Please see below for the St. Laurent investments and the in-service capital by year based on the Capital Update filed on June 16, 2023:

2024 Additions

St. Laurent Phase 4 - East/West (NPS12 Steel)	$ 51.8M
St. Laurent Phase 3 - Coventry/Cummings/St. Laurent (Plastic)	$ 23.9M
Total 2024 Additions	**$ 75.7M**

2025 Additions

St. Laurent Phase 3 - North/South (NPS12/16 Steel)	$121.9M
St. Laurent Phase 4 - Lower Section (Plastic)	$ 9.9M
St. Laurent Phase 3 - Montreal to Rockcliffe (Plastic)	$ 4.4M
St. Laurent Phase 4 - East/West (NPS12 Steel)	$ 2.7M
St. Laurent Phase 3 - Coventry/Cummings/St. Laurent (Plastic)	$ 1.7M
Total 2025 Additions	**$140.5M**

2026 Additions

St. Laurent Phase 3 - North/South (NPS12/16 Steel)	$ 6.4M
St. Laurent Phase 4 - Lower Section (Plastic)	$ 0.6M
St. Laurent Phase 3 - Montreal to Rockcliffe (Plastic)	$ 0.3M
Total 2026 Additions	**$ 7.2M**

ENBRIDGE GAS INC.

Answer to Undertaking from
Canadian Manufacturers & Exporters (CME)

Undertaking

Tr: 141

To review the projects listed in the March interrogatory response and in JT5.13 and advise the cause of the variance is between them.

Response:

Please see Attachment 1 which provides an updated view of Exhibit JT5.13, highlighting changes to values for each Value Measure and summary level causes for the changes.

This page is intentionally left blank. Due to size, this Attachment has not been included.

Please see Exhibit J13.22 Attachment 1.xlsx on the OEB's RDS.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 9

To explain the significant drop in fuel-switching numbers for the years up to 2032, on the pre- and post-capital update, Environmental Defence IR 94.

Response:

Enbridge Gas updates its forecast every year as new data becomes available. The customer additions forecast underpinning the pre-Capital Update response at Exhibit I.2.6-ED-94 was developed in 2022 by using the actual data up to 2021, while the post-Capital Update response was developed in 2023 by using actual data up to 2022. The significant drop in the fuel-switching residential customer additions forecast is driven by a steeper decline in trend resulting from 2022 actual data for fuel-switching residential customers, which resulted in a decline in the updated forecast for this specific group of customers relative to the initial forecast.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 13

To update customer connection and system reinforcement lines to reflect the energy-transition assumptions.

Response:

Table 1 provides the forecast of the Gas Infrastructure – Growth – Customer Connections asset class updated to account for Energy Transition impacts to customer connection activities.

Table 1

Investment Sub-Category ($ millions)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Gas Infrastructure - Growth - Customer Connections w/ ET Assumptions	325.0	331.5	282.1	290.9	289.2	262.6	241.6	232.5	222.2	202.25	2679.74
Gas Infrastructure - Growth - Customer Connections w/o ET Assumptions	325.0	333.5	285.7	296.5	298.2	274.5	256.1	251.3	242.0	224.5	2787.3
Difference	0.0	-2.0	-3.6	-5.5	-9.1	-12.0	-14.5	-18.8	-19.8	-22.4	-107.6

Enbridge Gas has confirmed the System Reinforcement forecast reflects Energy Transition assumptions, Tr. Vol. 14, 12, lines 12 to 17:

> MR. MILLAR: Do I have it right that you did not account for the energy-transition assumptions for the customer connection line but that you did account for them in the system reinforcement line? Is that what that previous passage was indicating?
>
> MR. WELLINGTON: That's correct.

Enbridge Gas wishes to make a correction to the transcript for Day 14 of the Oral Hearing. In an exchange with Ms. Wade, Commissioner Moran references, amongst a series of items, a $3 million dollar difference due to energy transition risk, Tr. Vol. 14 109, line 2. In line 4, Ms. Wade confirms Commissioner Moran's general understanding of how energy transition was factored into the demand forecast; however, Ms. Wade would like to address Commissioner Moran's reference to "$3 million per year, with or without energy transition factored in". Subsequent to the Hearing and upon reflection, Ms. Wade presumes Commissioner Moran is referencing the impact of the energy transition adjustment to the customer connections forecast.

In Exhibit 1, Tab 10, Schedule 4 page 8, Enbridge Gas notes the following, "as a result of the energy transition adjustment to the customer forecast, the 2024 Test Year general service annual volume forecast is approximately 2,899,408 cubic meters per year lower than would otherwise be the case." (emphasis added). This 2.9M m3 volume reduction was subsequently updated as provided in Exhibit I.1.10-STAFF-31 with a corrected volume of 1,062,274 cubic meters in the 2024 Test Year.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 15

To explain the difference in the customer connection capital requirements, with and without energy transition changes that occurred pre- and post-capital update.

Response:

The customer connection forecast provided prior to the capital update was established based on average customer connection costs from 2021 and the prior two years. As stated in Panel 11 opening remarks, costs have increased considerably over the past several years for various reasons; and upon recognizing the impact to the 2024 forecast, Enbridge Gas updated the forecast to reflect the cost pressures that it has seen over the last three years, and which are expected to continue in the future.

The capital update is based on the customer forecast without energy transition changes. The impacts on capital due to energy transition changes on the customer forecast can be found in Exhibit I.2.6-Staff-72. Note that this interrogatory response was updated as part of the capital update.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Greenhouse Vegetable Growers (OGVG)

Undertaking

Tr: 36

To rerun Table 1 (the large-customer-free version to be provided as undertaking J10.10) excluding capitalized overhead, on a best-efforts basis.

Response:

Enbridge Gas is unable to provide the table with the large customers excluded for all years and revenue horizon scenarios. The estimated costs associated with large volume contract customers who are subject to a revenue horizon of 20 years or less is approximately $50 million for 2024. The 2024 year in the table below has been reduced by $50 million in all scenarios. Please see Exhibit J10.10 for information regarding distribution contract market (i.e. large volume) customers costs.

Table 1 has been revised to exclude indirect overheads allocations in each of the revenue horizon scenarios. Please see below:

Table 1 Without Overheads
Customer Connections Capital Expenditure Supported by Different Revenue Horizons

Revenue Horizons	2024	2025	2026	2027	2028	Total	Reduction vs 40 Year Revenue Horizon	CIAC per Customer (without overheads
(Years)	($millions)	($millions)	($millions)	($millions)	($millions)	($millions)	($millions)	
40	190.7	195.4	192.9	188.9	181.6	949.5		
30	127.9	177.9	178.3	178.8	176.2	839.1	110.4	573
25	112.6	162.6	162.9	163.5	163.7	765.3	184.2	956
15	61.8	111.7	112.0	112.3	110.6	508.4	441.1	2288
10	17.2	67.2	67.2	67.2	67.2	286.2	663.3	3441

Note: 40-year revenue horizon reflects the Company's most updated capital forecast

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Greenhouse Vegetable Growers (OGVG)

Undertaking

Tr: 40

On a best efforts basis, to redo the table at Exhibit I.2.5-SEC-107 Attachment 1, as updated to July 26, 2023, extracting capitalized overhead amounts from the line items over the 2021 to 2028 period and including total annual capitalized overhead amounts for all years in the same manner as presented for the 2014-2020 period on line 12, and to split out each line item into two lines, with one line containing the spending that was or will not be subject to leave to construct approval and the second line containing the spending that was or will be subject to leave to construct approval.

Response:

Enbridge Gas interprets the request to be referring to the table at Exhibit I.2.5-SEC-107, Attachment 1 updated on July 6, 2023, reflecting the Capital Update.

Please see Attachment 1 which includes capitalized overheads removed from the asset class presentation from 2021 to 2028. Note that leave to construct projects have been split out or flagged for the following asset classes and line items:

- Compression Stations
- Distribution Pipe
- Growth – Distribution System Reinforcements
- Transmission Pipe and Underground Storage
- GTA
- CPT
- Community Expansion

Table 1
Utility Capital Expenditures by Asset Class

Line No.	Particulars ($ millions)	Utility	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Estimate	2024 Test Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	Compression Stations	EGI		13.9	26.8	19.9	22.6	10.6	18.3	26.5	34.4	53.4	22.6	23.7	29.8	37.5	95.7	13.9
2	Compression Stations - LTC	EGI		-	-	-	-	-	-	-	-	31.8	226.0	12.7	20.9	0.1	-	-
3	Customer Connections	EGI		175.4	162.0	154.8	147.0	151.1	190.4	178.7	211.7	237.1	221.1	238.7	195.4	192.9	188.9	181.6
4	Distribution Pipe	EGI		93.4	96.3	132.8	138.7	139.6	149.5	147.9	251.1	292.9	157.5	212.4	231.8	206.7	186.5	229.8
5	Distribution Pipe - LTC	EGI		26.2	24.2	11.2	5.5	0.2	25.6	44.9	112.9	89.6	26.2	68.3	94.6	5.4	-	-
6	Distribution Stations	EGI		27.2	32.6	38.7	39.0	38.1	39.7	61.4	74.2	77.6	52.1	65.7	89.1	78.8	59.1	84.5
7	Fleet & Equipment	EGI		28.6	22.1	7.8	18.9	15.3	26.3	20.2	21.7	24.4	6.9	24.8	27.9	30.1	34.1	38.0
8	Growth - Distribution System Reinforcement	EGI		11.9	0.7	23.2	19.6	25.9	31.3	19.3	34.8	55.5	38.1	44.5	34.9	24.7	34.4	7.5
9	Growth - Distribution System Reinforcement - LTC	EGI		8.3	19.6	19.1	7.0	10.5	108.6	50.8	4.8	0.4	4.6	22.3	122.6	7.8	-	-
10	Real Estate & Workplace Services	EGI		24.9	36.3	30.3	17.4	21.2	42.0	38.3	57.2	51.3	48.6	49.3	48.3	69.1	23.9	40.9
11	Technology Information Services (TIS)	EGI		48.5	46.8	42.6	50.1	56.6	48.9	22.7	18.5	22.4	36.4	80.2	61.4	53.4	33.4	39.3
12	Transmission Pipe and Underground Storage	EGI		12.1	26.8	12.9	20.6	17.9	20.0	32.5	38.7	48.3	31.0	48.2	54.4	47.6	63.1	123.4
13	Transmission Pipe and Underground Storage - LTC	EGI		-	-	0.1	0.9	0.6	0.3	0.9	26.0	2.3	30.3	6.2	59.6	103.0	138.0	-
14	Utilization	EGI		66.9	71.7	73.3	74.6	75.2	99.3	62.9	65.6	78.8	124.3	119.8	126.1	129.5	113.2	122.3
15	Extended Alliance Fixed Overhead	EGI		13.7	17.0	17.3	17.1	15.8	17.8	19.5	25.4	27.0	25.6	39.8	40.8	41.9	43.0	23.2
16	Capitalized Overheads	EGI		197.8	200.2	212.5	209.8	207.0	215.2	220.9	235.0	271.8	305.9	277.5	323.0	329.5	329.6	332.1
17	Integration Capital	EGI		-	-	-	-	-	21.7	39.8	71.1	22.8	15.4	-	-	-	-	-
18	Community Expansion - LTC	EGI		-	-	-	7.8	4.1	17.1	20.9	17.4	14.2	20.6	11.2	19.6	20.5	21.5	7.3
19	GTA - LTC	EGI		172.4	551.1	114.8	4.8	-	-	-	-	-	-	-	-	-	-	-
20	WAMS	EGI		19.3	27.5	35.7	2.0	-	-	-	-	-	-	-	-	-	-	-
21	CPT - LTC	EGI		154.6	352.6	690.8	367.9	156.1	11.4	-	-	-	-	-	-	-	-	-
22	Other	EGI		3.0	0.3	1.2	2.5	0.2	3.9	(0.9)	10.5	1.1	34.3	124.6	43.9	28.3	28.0	35.7
23	Union Unregulated	EGI		(9.2)	(7.9)	(11.0)	(21.2)	(13.4)	-	-	-	-	-	-	-	-	-	-
24	Total		886.0	1,089.2	1,706.7	1,628.0	1,152.6	932.6	1,087.4	1,007.2	1,310.8	1,402.9	1,427.2	1,470.3	1,623.8	1,406.7	1,392.3	1,279.5

Notes:

(1) Capital expenditures are shown on an annual basis

(2) Expenditures are net of contributions and include IDC

(3) Panhandle Regional Expansion Project capex reductions of $34.2M in 2022, $22.7M in 2023 Bridge Year, $24.5M in 2023 Actual, $194.9M in 2024 and $6.7M in 2025

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Greenhouse Vegetable Growers (OGVG)

Undertaking

Tr: 43

Referring to JT5.13, Attachment 1, page 52 of the SEC compendium, to confirm whether each of the projects are considered value-driven projects.

Response:

Please see the Excel file in Attachment 1 which provides an update to Exhibit JT5.13 Attachment 1 including a column to identify planning group. This file also provides forecasted capital expenditures in 2023 and 2024, as requested in Exhibit J14.7.

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
No Longer in Plan	Distribution Pipe	WIND: Devonshire Rd, Windsor, Replacement	49729	Value Driven	-	-	1,188	(181)	1,369	0.00	28.99	0.00	57.16	0.05	122.26	0.00	0.00	0.00	0.00	0.35	56.42	0.00	0.00	0.00	0.00	0.00	36.15	1,057.97	9.17
No Longer in Plan	Distribution Pipe	NE: Whittaker St., Sudbury, Replacement	48553	Value Driven	-	-	24	(229)	253	0.00	0.00	0.00	0.00	0.00	0.00	0.00	105.80	0.00	0.00	0.00	28.49	0.00	0.00	0.00	0.00	0.00	3.61	105.80	9.21
Existing Investment	Distribution Pipe	WIND: Laird & Centre MIP, Essex, Replacement	48994	Value Driven	-	-	277	(990)	1,267	0.00	26.83	0.00	52.90	0.04	113.15	0.00	0.00	0.00	0.00	0.33	52.22	0.00	0.00	0.00	0.00	0.00	33.45	979.11	8.49
Existing Investment	Distribution Pipe	WIND: County Rd 27 Ph 2, Lakeshore, Replacement	102257	Value Driven	-	-	491	(779)	1,270	0.00	27.35	0.00	53.93	0.04	115.36	0.00	0.00	0.00	0.00	0.33	52.22	0.00	0.00	0.00	0.00	0.00	33.45	979.11	8.49
No Longer in Plan	Distribution Pipe	WIND: Woodslee, Lakeshore, Replacement	102262	Value Driven	-	-	917	(451)	1,369	0.00	28.99	0.00	57.16	0.05	122.26	0.00	0.00	0.00	0.00	0.35	56.42	0.00	0.00	0.00	0.00	0.00	36.15	1,057.97	9.17
Existing Investment	Distribution Pipe	WIND: Riverside Aldyl A - Ph 2, Windsor, Replacement	100688	Value Driven	-	-	916	(1,453)	2,369	0.00	12.41	0.00	0.00	0.00	52.36	0.00	979.12	0.00	0.00	0.00	52.22	0.00	0.00	0.00	0.00	0.00	285.57	979.11	8.49
No Longer in Plan	Distribution Pipe	CHAT: Ridgetown LP, Ridgetown, Replacement	49742	Value Driven	-	-	1,539	(984)	2,522	0.00	8.30	0.00	33.34	28.58	35.00	0.00	1,057.97	0.00	0.00	0.35	284.95	0.00	0.00	0.00	0.00	0.00	0.00	1,057.97	15.96
No Longer in Plan	Distribution Pipe	CHAT: Tweedsmuir LP, Chatham, Replacement	49859	Value Driven	-	-	20,317	(1,566)	21,883	0.00	0.00	0.00	57.16	3.19	0.00	0.00	10,579.67	0.00	0.00	3.53	564.25	0.00	0.00	0.00	0.00	0.00	3.61	10,579.67	91.69
Emergent	Distribution Pipe	Sarnia Industrial Line Environmental Monitoring	739745	Mandatory	$ 40,470	$ 40,838	(138)	(138)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Prince Arthur Blvd-Thunder Bay-1538	30156	Value Driven	-	-	(1,475)	(1,543)	68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.83	0.00	0.00	0.00	0.30	0.00	0.00	5.21	0.75
No Longer in Plan	Distribution Pipe	Briscoe St W - Southwest - London -1735	30278	Value Driven	-	-	(1,517)	(1,583)	66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.87	0.00	0.00	0.00	0.28	0.00	0.00	4.59	0.66
Existing Investment	Distribution Pipe	Manse Alley-Gananoque-1466	30429	Value Driven	-	-	(2,445)	(2,531)	86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	82.64	0.00	0.00	0.00	0.07	0.00	0.00	2.79	0.41
No Longer in Plan	Distribution Pipe	Base Line Rd E - Southwest - London - 1461	30277	Value Driven	-	-	(2,369)	(2,715)	346	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	313.89	0.00	0.00	0.00	0.00	0.00	0.00	28.17	3.55
Existing Investment	Distribution Pipe	Arthur St W (EXECUTE 2024) -Thunder Bay-1496	30136	Value Driven	-	-	(1,949)	(1,983)	35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.96	0.00	0.00	0.00	6.46	0.00	0.00	1.15	0.15
Existing Investment	Distribution Pipe	4th Ave S-Kenora-1562	30134	Value Driven	-	-	(1,836)	(1,882)	46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.09	0.00	0.00	0.00	0.11	0.00	0.00	3.72	0.54
Existing Investment	Distribution Pipe	Maple St N-Timmins-1535	30150	Value Driven	-	-	(1,651)	(1,698)	47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.06	0.00	0.00	0.00	0.10	0.00	0.00	4.07	0.58
Existing Investment	Distribution Pipe	Wellington Rd (EXECUTE 2025 - BRT DESIGNS EXPECTED 2025) - Southw	30325	Value Driven	-	-	(1,753)	(2,299)	546	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	498.75	0.00	0.00	0.00	0.36	0.00	0.00	41.41	5.44
Existing Investment	Distribution Pipe	Hamilton - Crooks St 2 -VSM Replacement	30406	Value Driven	-	-	(1,340)	(1,378)	39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.43	0.00	0.00	0.00	0.22	0.00	0.00	3.67	0.52
Existing Investment	Distribution Pipe	Rholaine Dr - Southwest - Windsor - 1299	30033	Value Driven	-	-	(1,018)	(1,078)	60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.62	0.00	0.00	0.00	0.13	0.00	0.00	5.55	0.74
No Longer in Plan	Distribution Pipe	Lanoue St - Southwest - Windsor - 1354	30022	Value Driven	-	-	(617)	(923)	306	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	284.52	0.00	0.00	0.00	0.04	0.00	0.00	18.98	2.80
No Longer in Plan	Distribution Pipe	Hamilton Rd - Southwest - London - 1408	30301	Value Driven	-	-	(1,724)	(1,986)	262	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	249.72	0.00	0.00	0.00	0.13	0.00	0.00	10.68	1.59
Existing Investment	Distribution Pipe	Delaware Ave - Southwest - Windsor - 1364	30010	Value Driven	-	-	(1,148)	(1,211)	63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.54	0.00	0.00	0.00	0.26	0.00	0.00	4.00	0.56
Existing Investment	Distribution Pipe	Creston Ave - Southwest - London - 1734	30285	Value Driven	$ 15,785	-	(540)	(835)	296	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	270.63	0.00	0.00	0.00	0.73	0.00	0.00	21.34	3.06
Existing Investment	Distribution Pipe	Cedar Alley-Gananoque-1455	30420	Value Driven	-	-	(1,507)	(1,594)	87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	83.81	0.00	0.00	0.00	0.12	0.00	0.00	2.53	0.40
Existing Investment	Distribution Pipe	WATE: Norfolk County Rd 21, Andy's Corners, VSM Replacement	30260	Value Driven	-	-	(836)	(979)	143	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	140.27	0.00	0.00	0.00	0.06	0.00	0.00	0.58	1.60
Emergent	Distribution Pipe	The Parkway - Southwest - London - 1432	30324	Value Driven	$ 4,174	-	(881)	(973)	92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86.97	0.00	0.00	0.00	0.07	0.00	0.00	4.58	0.67
No Longer in Plan	Distribution Pipe	Briscoe St W Ph 2 - Southwest - London - 1736	30279	Value Driven	-	-	(1,661)	(1,801)	140	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	129.42	0.00	0.00	0.00	0.95	0.00	0.00	8.10	1.15
Existing Investment	Distribution Pipe	Div. 16 - Hamilton - Crooks St 1 - Hamilton - 1745	30405	Value Driven	-	-	(1,357)	(1,431)	74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.83	0.00	0.00	0.00	0.26	0.00	0.00	6.11	0.83
Existing Investment	Distribution Pipe	Southdale Rd E - Southwest - London - 1434	30319	Value Driven	-	-	(2,628)	(3,726)	1,097	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,012.63	0.00	0.00	0.00	43.33	0.00	0.00	36.76	4.68
Existing Investment	Distribution Pipe	Presley St 1 - Northeast - 1713	30228	Value Driven	-	-	(1,182)	(1,239)	57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.21	0.00	0.00	0.00	0.19	0.00	0.00	4.19	0.62
Existing Investment	Distribution Pipe	Spring Garden Rd - Southwest - Windsor - 1658	30037	Value Driven	-	-	(925)	(1,084)	159	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	150.13	0.00	0.00	0.00	0.43	0.00	0.00	7.35	1.06
Emergent	Compression Stations	SCOR: Boiler & Gen Start Air OPP Upgrades	740931	Mandatory	-	$ 168,765	(118)	(118)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	SCOR:171 Emerg Vent System - Upgrade	740925	Mandatory	-	$ 19,929	(511)	(511)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	SCOR: 64111 Gearbox and Glycol Pump Upgrade	740891	Mandatory	-	$ 160,070	(112)	(112)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	SCOR:172 Flare Knock-out - OPP Upgrade	740875	Mandatory	-	$ 176,734	(146)	(146)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	SCOR:541 Condensate System MOP/OPP Upgrade	740924	Mandatory	-	$ 213,213	(521)	(521)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	SCOR: Link ESV-009 Replace	739291	Mandatory	-	-	(273)	(273)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Compression Stations	SCOR:60011-Fdn Blk-Replace	12884	Value Driven	-	-	847	(1,067)	1,914	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,914.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	SSOM: V-0806 Iso Valves - Replace	738093	Mandatory	-	$ 589,057	(434)	(434)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Compression Stations	SCOR:60004-Fdn Blk-Replace	5624	Value Driven	$ 3,504,525	-	4,201	(2,366)	6,566	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6,566.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Weston Rd & Imogene trespassing main	2698	Value Driven	$ 32,449	-	(131)	(426)	295	0.00	0.00	0.00	0.00	0.00	0.00	0.00	123.51	0.00	0.00	0.00	33.27	0.00	0.00	0.00	0.00	0.00	4.22	123.51	10.76
Existing Investment	Distribution Stations	NGT Existing customer Maintenance Capital - (+2027)	17403	Value Driven	-	-	(1,190)	(1,190)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NGV Rental VRA's - (2026-2032)	17404	Value Driven	-	-	(601)	(601)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	Peterborough - CNG Station	738065	Mandatory	$ 46,971	-	(633)	(633)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	Lisgar Station	503369	Value Driven	$ 129,797	-	(12,955)	(13,113)	158	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.33	0.00	0.00	0.00	0.00	0.00	4.43	153.40	0.09
No Longer in Plan	Distribution Stations	VINELAND GATE	7760	Compliance	-	-	(458)	(503)	45	0.00	0.00	0.00	0.00	8.54	0.00	0.00	0.00	0.00	0.00	0.00	36.15	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00
No Longer in Plan	Distribution Stations	THOROLD TOWNLINE GATE	7759	Value Driven	-	-	(515)	(531)	17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NIAGARA GATE	7752	Value Driven	$ 32,449	-	(2,556)	(2,707)	151	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	150.66	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00
Existing Investment	Distribution Stations	MOUNTAIN RD GATE	3620	Value Driven	-	-	(2,188)	(2,266)	78	0.00	0.00	0.00	0.00	11.43	0.00	0.00	0.00	0.00	0.00	0.00	66.82	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.14
No Longer in Plan	Distribution Stations	TALISMAN PRODUCTION	16586	Value Driven	-	-	(837)	(1,098)	262	0.00	0.00	0.00	0.00	51.40	0.00	0.00	0.00	0.00	0.00	0.00	209.40	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.53
No Longer in Plan	Distribution Stations	PETAWAWA GATE	7755	Value Driven	-	-	(253)	(254)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.01
No Longer in Plan	Distribution Stations	KEMPTVILLE GATE	7751	Value Driven	-	-	(3,205)	(3,207)	1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.94	0.00	0.00	0.00	0.00	0.00	0.16	0.21	0.00
No Longer in Plan	Distribution Stations	LEEDS GATE	1012	Value Driven	-	-	(629)	(632)	3	0.00	0.15	0.00	0.00	0.00	0.62	0.00	0.00	0.00	0.00	0.08	1.42	0.00	0.00	0.00	0.00	0.00	0.39	0.00	0.02
No Longer in Plan	Distribution Stations	SUMMERSTOWN GATE	3622	Mandatory	-	-	(2,138)	(2,160)	22	0.00	0.00	0.00	0.00	19.18	0.00	0.00	0.00	0.00	0.00	0.08	2.37	0.00	0.00	0.00	0.00	0.00	0.01	0.11	0.02
Existing Investment	Distribution Stations	BROCKVILLE GATE	3608	Value Driven	-	$ 1,188,753	(1,681)	(1,736)	56	0.00	0.00	0.00	0.00	17.86	0.00	0.00	0.00	0.00	0.00	0.09	36.34	0.00	0.00	0.00	0.00	0.00	0.95	0.25	0.36
Existing Investment	Distribution Stations	THORNTON GATE	7758	Value Driven	$ 64,899	-	(2,739)	(2,841)	102	0.00	0.00	0.00	0.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	101.98	0.00	0.00	0.00	(0.00)	0.00	0.00	0.01	(0.00)
Existing Investment	Distribution Stations	DURHAM 23 FEEDER	7766	Value Driven	-	-	(778)	(1,063)	285	0.00	0.00	0.00	0.00	60.90	0.00	0.00	0.00	0.00	0.00	0.00	223.87	0.01	0.00	0.00	0.00	0.00	0.00	0.11	0.00
Existing Investment	Distribution Stations	OSHAWA GATE	7754	Value Driven	$ 32,449	-	(2,518)	(2,520)	2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.44	0.00	0.00	0.00	0.59	0.00	0.00	0.10	0.04
Existing Investment	Distribution Stations	BAYVIEW FEEDER	3605	Value Driven	$ 1,538,097	-	(5,207)	(5,275)	68	0.00	0.20	0.00	0.00	0.00	0.83	0.00	0.00	0.00	0.00	0.00	36.37	0.00	0.00	0.00	0.00	0.00	21.92	0.00	8.78
Existing Investment	Distribution Stations	NOBLETON GATE	7753	Value Driven	-	$ 75,744	(2,494)	(2,582)	88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.92
Existing Investment	Distribution Stations	SCHOMBERG GATE	1011	Value Driven	$ 77,878	-	(3,317)	(3,714)	397	0.00	0.00	0.00	0.00	21.11	0.00	0.00	0.00	0.00	0.00	0.00	370.30	(0.01)	0.00	0.00	5.09	0.00	0.00	0.12	0.43
Emergent	Distribution Stations	WATE: 23R-602 Rothsay Distribution Station, Full Station Rebuild, Obsol	740307	Value Driven	-	$ 530,205	(311)	(311)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	BOWMANVILLE GATE	7749	Mandatory	-	-	(2,815)	(3,003)	188	0.00	0.00	0.00	0.00	3.62	0.00	0.00	0.00	0.00	0.00	0.00	184.21	0.04	0.00	0.00	0.00	0.00	0.00	0.05	0.41
No Longer in Plan	Distribution Stations	SANDALWOOD GATE	7757	Value Driven	-	-	73	(255)	329	0.00	0.00	0.00	0.00	70.24	0.00	0.00	0.00	0.00	0.00	0.00	258.17	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00
No Longer in Plan	Distribution Stations	EASTGATE AND DIXIE DISTRICT	7781	Compliance	-	-	(441)	(449)	8	0.00	0.00	0.00	0.00	3.80	0.00	0.00	0.00	0.00	0.00	0.00	4.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	BOND HEAD GATE	3614	Value Driven	-	-	(3,900)	(4,154)	254	0.00	0.00	0.00	0.00	8.67	0.00	0.00	0.00	0.00	0.00	0.00	242.86	0.00	0.00	0.00	0.79	0.00	0.00	0.58	1.33
Existing Investment	Distribution Stations	VICTORIA SQUARE GATE	3624	Value Driven	$ 32,449	-	(145)	(962)	817	0.00	0.00	0.00	0.00	17.88	0.00	0.00	0.00	0.00	0.00	0.00	799.22	0.00	0.00	0.00	0.09	0.00	0.00	0.06	0.18
Existing Investment	Distribution Stations	Buttonville Interconnect	733506	Compliance	-	-	(61)	(61)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	BATHURST GATE	1148	Value Driven	-	-	(1,784)	(2,502)	717	0.00	0.00	0.00	0.00	1.25	0.00	0.00	0.00	0.00	0.00	0.00	188.08	0.00	0.00	0.00	527.97	0.00	0.00	0.01	0.10
No Longer in Plan	Distribution Stations	CROWLAND STORAGE TRANSFER	3610	Value Driven	-	-	(1,937)	(2,036)	100	0.00	0.00	0.00	0.00	17.68	0.00	0.00	0.00	0.00	0.00	0.00	81.53	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.48
No Longer in Plan	Distribution Stations	MARKHAM GATE	1013	Value Driven	-	-	(3,538)	(3,718)	180	0.00	0.00	0.00	0.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	178.25	0.00	0.00	0.00	0.68	0.00	0.00	0.18	0.24
Existing Investment	Distribution Stations	KEELE AND STEELES/CNR FEEDER	7769	Value Driven	-	-	(2,317)	(2,726)	410	0.00	0.00	0.00	0.00	84.45	0.00	0.00	0.00	0.00	0.00	0.00	324.95	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.20
No Longer in Plan	Distribution Stations	WOODBINE & CNR FEEDER	7778	Value Driven	-	-	(1,148)	(1,354)	206	0.00	0.00	0.00	0.00	43.73	0.00	0.00	0.00	0.00	0.00	0.00	162.09	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00
Emergent	Distribution Stations	3321291 - Bathurst Gate Station - Boiler 1 Replacement	739731	Compliance	$ 84,368	-	247	(48)	296	0.00	0.00	0.00	0.00	30.60	0.00	0.00	0.00	0.00	0.00	0.00	264.74	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.16
No Longer in Plan	Distribution Stations	CATHCART & STEWART DISTRICT	7763	Value Driven	-	-	1,395	(833)	2,228	0.00	0.00	0.00	0.00	72.25	0.00	0.00	0.00	0.00	0.00	0.00	436.16	0.00	0.00	0.00	1,711.43	0.00	0.00	0.13	7.94
No Longer in Plan	Distribution Stations	YONGE AND STEELES FEEDER	2719	Value Driven	-	-	(72)	(293)	221	0.00	0.00	0.00	0.00	47.61	0.00	0.00	0.00	0.00	0.00	0.00	173.69	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00
Existing Investment	Distribution Stations	KEELE AND FINCH FEEDER	1147	Value Driven	$ 64,899	$ 227,231	(3,453)	(3,500)	46	0.00	0.20	0.00	0.00	0.00	0.83	0.00	0.00	0.00	0.00	0.00	36.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.78
Emergent	Distribution Stations	NPS 30 Beechwood Valve Actuation	733463	Value Driven	-	-	(56)	(56)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	DOWNSVIEW FEEDER	7765	Compliance	-	-	(230)	(247)	17	0.00	0.00	0.00	0.00	5.93	0.00	0.00	0.00	0.00	0.00	0.00	10.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	NEILSON RD FEEDER	7773	Compliance	-	-	(319)	(500)	182	0.00	0.00	0.00	0.00	36.56	0.00	0.00	0.00	0.00	0.00	0.00	145.15	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00
No Longer in Plan	Distribution Stations	SIGNET & FINCH FEEDER	7775	Value Driven	-	-	(17)	(229)	212	0.00	0.00	0.00	0.00	42.65	0.00	0.00	0.00	0.00	0.00	0.00	169.30	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00
No Longer in Plan	Distribution Stations	Portland Energy Center - Electrical	501539	Mandatory	$ -	$ -	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	CAWTHRA AND QUEENSWAY DISTRICT	1043	Value Driven	$ 64,899	$ 384,167	(1,542)	(2,015)	473	0.00	0.00	0.00	0.00	103.42	0.01	0.00	0.00	0.00	0.00	0.00	368.52	0.02	0.00	0.00	0.00	0.00	0.00	0.54	0.20
Emergent	Distribution Pipe	Area 10 - Denison Rd E, North York	737637	Compliance	$ 64,899	-	(48)	(48)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Red Maple Dr Lincoln - 1-inch steel main replacement	103520	Value Driven	-	-	286	(187)	473	0.00	78.95	0.00	0.00	0.00	332.98	0.00	0.03	0.00	0.00	0.00	26.14	0.00	0.00	0.00	0.00	0.00	33.45	0.00	1.58
Existing Investment	Distribution Pipe	Viewmount Dr Main Lowering	734590	Value Driven	-	-	(195)	(225)	30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.14	0.00	0.00	0.00	0.00	0.00	22.63	0.00	2.82
No Longer in Plan	Distribution Pipe	Bannerman Crt. and Nordic Crt, Whitby	100470	Value Driven	-	-	693	(572)	1,265	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00	11.43	60.97	0.00	0.00	0.00	0.00	0.00	39.06	1,143.13	9.91
Existing Investment	Distribution Pipe	Campbellford Replacement Phase 3 Front St	102671	Value Driven	$ 649	$ 654,785	1,768	(458)	2,226	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.34	391.44	0.00	0.00	0.00	0.00	0.00	455.94	1,334.45	30.58
No Longer in Plan	Distribution Pipe	Campbellford Replacement Phase 5 Pellissier St & Bridge St	102673	Value Driven	-	-	1,317	(589)	1,907	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.43	335.32	0.00	0.00	0.00	0.00	0.00	390.57	1,143.13	26.20
Existing Investment	Distribution Pipe	Invergordon Ave, Toronto 3" PE Replacement	100512	Value Driven	-	-	(765)	(835)	70	0.00	11.88	0.00	0.00	0.00	50.11	0.00	0.00	0.00	0.00	0.00	3.62	0.00	0.00	0.00	0.00	0.00	4.22	0.00	0.02
No Longer in Plan	Distribution Pipe	Meadowvale & Sheppard CC Replacement	2334	Value Driven	-	-	70	(203)	273	0.00	0.00	0.00	0.00	0.00	0.00	0.00	114.31	0.00	0.00	0.00	30.79	0.00	0.00	0.00	0.00	0.00	3.91	114.31	9.95
Existing Investment	Distribution Pipe	Bloor St. W. & The Kingsway Replacement	1702	Value Driven	-	$ 19,208	(252)	(387)	135	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.35	0.00	0.00	0.00	33.27	0.00	0.00	0.00	0.00	0.00	42.20	12.35	35.08
Emergent	Distribution Pipe	A60: Jonathan Pack St Goulbourn	738932	Value Driven	$ (26,028)	-	27	27	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Concord St Isolated Steel Replace with Main St PE, Ottawa	23126	Value Driven	$ 909	-	(398)	(398)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	VPM - 310 Cathcart St Header - Aldyl A	23190	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	A60: Casselman Bridge Repair	740151	Value Driven	$ 289,837	-	(214)	(214)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Shallow Main - High Street from Dunlop to Park St	736572	Value Driven	$ 1	$ 13	(186)	(186)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Replacement - Vintage PE Lined Mains - Peterborough	101277	Value Driven	-	-	(327)	(1,359)	1,032	0.00	5.65	0.00	0.00	0.00	23.84	0.00	0.00	0.00	0.00	9.06	48.32	0.00	0.00	0.00	0.00	0.00	30.96	906.09	7.85
Emergent	Distribution Pipe	A60: Tenth Line Rd & Innes Rd Valve Replacement	739106	Value Driven	$ 765,438	-	(569)	(569)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
Emergent	Distribution Pipe	GTA Project Land Registration Work	739600	Value Driven	$ 9,460	-	(7)	(7)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Isolation Valve Mississauga	738889	Value Driven	-	$ 89,639	(63)	(63)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Erin Mills and Leanne Vital	1193	Value Driven	-	-	371	(882)	1,253	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	564.25	0.00	0.00	0.00	0.00	0.00	528.98	0.00	159.58
Existing Investment	Distribution Pipe	A:10 Dawlish Ave & Valleyanna Dr	736024	Value Driven	$ 2,422,688	-	(1,822)	(1,822)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Evans Industrial Replacement- Network # 123_368_373	733665	Value Driven	-	-	(412)	(412)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Jeffrey St - Area 50 - 1199	30086	Value Driven	-	-	(824)	(844)	20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.68	0.00	0.00	0.00	0.01	0.00	0.00	1.17	0.16
Existing Investment	Distribution Pipe	TOR10YR - Carnforth and Wyndcliff Replacement - Network # 455	735863	Value Driven	-	-	(1,465)	(1,465)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Mooregate and Treverton Replacement - Network # 455	735492	Value Driven	-	-	(588)	(588)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Amethyst and Cass Replacement - Network # 455	735820	Value Driven	-	-	(1,962)	(1,962)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	McGonigal St E - Eastern - Area 60 - 1041	30368	Value Driven	-	-	(869)	(952)	83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	79.24	0.00	0.00	0.00	0.14	0.00	0.00	3.21	0.47
Existing Investment	Distribution Pipe	Ferris Ln - Area 50 - 1201	30085	Value Driven	-	-	(1,076)	(1,156)	80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	76.19	0.00	0.00	0.00	0.31	0.00	0.00	3.36	0.46
Existing Investment	Distribution Pipe	Hillcrest Ave STC - Area 80 - 1176	30057	Value Driven	-	-	(869)	(890)	21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.84	0.00	0.00	0.00	0.07	0.00	0.00	0.69	0.10
Existing Investment	Distribution Pipe	Neff St PTC - Area 80 - 1165	30065	Value Driven	-	-	(581)	(598)	17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.29	0.00	0.00	0.00	0.03	0.00	0.00	0.89	0.13
Existing Investment	Distribution Pipe	Trenton Ave - Eastern - Area 60 - 1181	30390	Value Driven	-	-	(996)	(1,040)	44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.29	0.00	0.00	0.00	0.36	0.00	0.00	1.28	0.17
Existing Investment	Distribution Pipe	Geneva St STC - Area 80 - 1187	30055	Value Driven	-	-	(2,859)	(2,955)	95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	92.83	0.00	0.00	0.00	0.33	0.00	0.00	2.04	0.28
Emergent	Distribution Pipe	Cumberland St - Area 50 - 1200	30084	Value Driven	-	-	(597)	(643)	46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.94	0.00	0.00	0.00	0.18	0.00	0.00	1.92	0.27
Existing Investment	Distribution Pipe	Collier St (MORATORIUM UNTIL 2026) - Area 50 - 1216	30083	Value Driven	-	-	(386)	(415)	29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.83	0.00	0.00	0.00	0.03	0.00	0.00	1.18	0.17
Emergent	Distribution Pipe	Blake St - Area 50 - 1209	30082	Value Driven	-	-	(993)	(1,036)	43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.76	0.00	0.00	0.00	0.13	0.00	0.00	1.71	0.22
Emergent	Distribution Pipe	Anne St S - Area 50 - 1204	30081	Value Driven	-	-	(1,649)	(1,705)	56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	54.07	0.00	0.00	0.00	0.17	0.00	0.00	1.65	0.28
Existing Investment	Distribution Pipe	TOR10YR - Parklawn A1 A - Horner Replacement	503164	Value Driven	$ 2,726	-	(362)	(362)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Valentine and York Mills Replacement - Network # 455	735852	Value Driven	-	-	(918)	(918)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Ionview South Replacement - Network # 455	735501	Value Driven	-	-	(1,005)	(1,005)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Sheppard Ave & Brimley Rd (Compression Couplings)	2563	Value Driven	-	-	178	(96)	273	0.00	0.00	0.00	0.00	0.00	0.00	0.00	114.31	0.00	0.00	0.00	30.79	0.00	0.00	0.00	0.00	0.00	3.91	114.31	9.95
Existing Investment	Distribution Pipe	Flanders Ave STC - Area 80 - 1809	30056	Value Driven	$ 12,331	-	(1,209)	(1,275)	66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	62.73	0.00	0.00	0.00	0.22	0.00	0.00	2.80	0.39
Existing Investment	Distribution Pipe	2nd Ave PTC - Area 80 - 1180	30046	Value Driven	-	-	(1,554)	(1,604)	50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	47.80	0.00	0.00	0.00	0.15	0.00	0.00	2.10	0.30
Existing Investment	Distribution Pipe	TOR10YR - Bay Mills and Birchmount Services Replacement - Network #	735819	Value Driven	-	-	(1,182)	(1,182)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Laurentide and Silverdale Replacement - Network # 455	735848	Value Driven	-	-	(644)	(644)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Bay Mills and Birchmount Replacement - Network # 455	735817	Value Driven	-	-	(257)	(257)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Victoria St STC- Area 80 - 1148	30079	Value Driven	-	-	(459)	(477)	19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.90	0.00	0.00	0.00	0.03	0.00	0.00	0.79	0.11
Existing Investment	Distribution Pipe	Bayview & St. Leonards Compression Couplings	1692	Value Driven	-	-	163	(111)	273	0.00	0.00	0.00	0.00	0.00	0.00	0.00	114.31	0.00	0.00	0.00	30.79	0.00	0.00	0.00	0.00	0.00	3.91	114.31	9.95
Existing Investment	Distribution Pipe	Swan Dr STC- Area 80 - 1163	30078	Value Driven	-	-	(1,553)	(1,622)	68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	64.79	0.00	0.00	0.00	0.28	0.00	0.00	2.77	0.40
Existing Investment	Distribution Pipe	A80: Rose St STC, VS Replacement	30074	Value Driven	-	-	(306)	(328)	21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.36	0.00	0.00	0.00	0.03	0.00	0.00	0.95	0.13
Existing Investment	Distribution Pipe	AR40: VSM Replacement - Wilson Rd S Oshawa Ph 1B Dieppe Ave to Oli	735948	Value Driven	-	$ 64,028	(1,095)	(1,349)	255	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	252.04	0.00	0.00	0.00	1.58	0.00	0.00	1.08	0.15
Existing Investment	Distribution Pipe	Yonge St 2 - GTA East - Area 30 - 1707	30176	Value Driven	-	-	(730)	(750)	20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.43	0.00	0.00	0.00	0.03	0.00	0.00	0.87	0.12
Existing Investment	Distribution Pipe	TOR10YR - Browns and Owen Replacement- Network # 123_368_373	733677	Value Driven	-	-	(508)	(508)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Riverside Dr WELL- Area 80 - 1810	30072	Value Driven	$ -	$ -	(1,546)	(1,568)	23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.69	0.00	0.00	0.00	0.06	0.00	0.00	0.96	0.14
Existing Investment	Distribution Pipe	Cattell Dr NFalls- Area 80 - 1170	30049	Value Driven	-	-	(917)	(952)	34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.40	0.00	0.00	0.00	0.06	0.00	0.00	1.44	0.21
No Longer in Plan	Distribution Pipe	Sheppard & Markham Compression Couplings	2562	Value Driven	-	-	7	(267)	273	0.00	0.00	0.00	0.00	0.00	0.00	0.00	114.31	0.00	0.00	0.00	30.79	0.00	0.00	0.00	0.00	0.00	3.91	114.31	9.95
Existing Investment	Distribution Pipe	Queen St LINC - Area 80 - 1150	30071	Value Driven	-	-	(903)	(934)	31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.60	0.00	0.00	0.00	0.06	0.00	0.00	1.40	0.20
Existing Investment	Distribution Pipe	AR40: VSM Replacement - Wilson Rd S Oshawa Ph 2 Olive to King	735949	Value Driven	-	$ 128,056	(3,348)	(3,597)	249	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	246.39	0.00	0.00	0.00	1.54	0.00	0.00	1.04	0.15
Emergent	Distribution Pipe	Homewood Ave PTC - Area 80 - 1149	30059	Value Driven	-	-	(511)	(534)	23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.14	0.00	0.00	0.00	0.05	0.00	0.00	0.97	0.14
Existing Investment	Distribution Pipe	TOR10YR - Groveland and Lacewood Replacement - Network # 455	735851	Value Driven	-	-	(675)	(675)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Three Valley Dr Replacement - Network # 455	735850	Value Driven	-	-	(1,094)	(1,094)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	A80: Burleigh Hill Dr STC - VS Replacement	30048	Value Driven	-	-	(816)	(839)	24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.97	0.00	0.00	0.00	0.01	0.00	0.00	1.39	0.17
Existing Investment	Distribution Pipe	A80: Regional Rd 65, West Lincoln. Replacement	502019	Value Driven	-	-	(123)	(136)	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00	0.00	6.59	0.00	0.00	0.00	0.00	0.00	4.22	0.00	1.18
Existing Investment	Distribution Pipe	Briarsdale Dr STC - Area 80 - 1174	30047	Value Driven	-	-	(1,029)	(1,086)	56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.29	0.00	0.00	0.00	0.10	0.00	0.00	2.67	0.36
Emergent	Distribution Pipe	TOR10YR - Compton and Guild Hall Replacement - Network # 455	735846	Value Driven	-	-	(421)	(421)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Oshawa LP Replacement Phase 1 Olive Ave	100517	Value Driven	-	-	(2,424)	(2,655)	231	0.00	2.26	0.00	0.00	2.75	9.54	0.00	0.03	0.00	0.00	1.14	60.97	0.00	0.00	0.00	0.00	0.00	39.06	114.31	0.81
Existing Investment	Distribution Pipe	A80: Ridge Rd.N Fort Erie, VS Replacement	502017	Value Driven	-	-	(744)	(757)	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00	0.00	6.59	0.00	0.00	0.00	0.00	0.00	4.22	0.00	1.18
Existing Investment	Distribution Pipe	TOR10YR - Larabee and Tetbury Replacement - Network # 455	735849	Value Driven	-	-	(769)	(769)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Irene Cres - Eastern - Area 60 - 1141	30359	Value Driven	-	-	(1,080)	(1,117)	37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.53	0.00	0.00	0.00	0.30	0.00	0.00	1.20	0.16
Existing Investment	Distribution Pipe	2nd Ave - Eastern - Area 60 - 1197	30330	Value Driven	-	-	(1,289)	(1,334)	46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.55	0.00	0.00	0.00	0.60	0.00	0.00	1.20	0.16
No Longer in Plan	Distribution Pipe	Oshawa LP Replacement Phase 3 Masson St	103429	Value Driven	-	-	(4,781)	(4,991)	210	0.00	1.54	0.00	0.00	1.87	6.48	0.00	0.03	0.00	0.00	1.06	56.42	0.00	0.00	0.00	0.00	0.00	36.15	105.80	0.75
Existing Investment	Distribution Pipe	James St - Eastern - Area 60 - 1112	30360	Value Driven	-	-	(1,122)	(1,163)	41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.50	0.00	0.00	0.00	0.09	0.00	0.00	2.03	0.23
Existing Investment	Distribution Pipe	3rd Ave - Eastern - Area 60 - 1830	30331	Value Driven	-	-	(1,438)	(1,479)	41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.41	0.00	0.00	0.00	0.04	0.00	0.00	1.80	0.25
Existing Investment	Distribution Pipe	James St W - Eastern - Area 60 - 1184	30361	Value Driven	-	-	(1,073)	(1,111)	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.91	0.00	0.00	0.00	0.07	0.00	0.00	2.04	0.31
Emergent	Distribution Pipe	King George St - Eastern - Area 60 - 1143	30362	Value Driven	-	-	(996)	(1,047)	51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.73	0.00	0.00	0.00	0.52	0.00	0.00	1.73	0.25
Existing Investment	Distribution Pipe	Lake Ave E - Eastern - Area 60 - 1145	30363	Value Driven	-	-	(1,345)	(1,385)	40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.63	0.00	0.00	0.00	0.48	0.00	0.00	1.13	0.16
Existing Investment	Distribution Pipe	Adelaide St - Eastern - Area 60 - 1828	30332	Value Driven	-	-	(245)	(253)	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.71	0.00	0.00	0.00	0.02	0.00	0.00	0.26	0.04
Existing Investment	Distribution Pipe	TOR10YR - Birchmount South Sheppard Replacement - Network # 455	735830	Value Driven	-	-	(1,677)	(1,677)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Oshawa LP Replacement Phase 2 King St	103427	Value Driven	-	-	(3,049)	(3,296)	247	0.00	2.09	0.00	0.00	2.55	8.83	0.00	0.04	0.00	0.00	1.24	65.87	0.00	0.00	0.00	0.00	0.00	42.20	123.51	0.87
Existing Investment	Distribution Pipe	TOR10YR - Kingsdown and Ranstone Replacement - Network # 455	735497	Value Driven	-	-	(1,228)	(1,228)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Elm St E - Eastern - Area 60 - 1147	30346	Value Driven	-	-	(987)	(1,022)	34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.57	0.00	0.00	0.00	0.05	0.00	0.00	1.37	0.19
Existing Investment	Distribution Pipe	VSM - LePage Ave (EXECUTE BY 2025 - PAVING PROPOSED BETWEEN 2(	30364	Value Driven	-	-	(1,547)	(1,602)	55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.47	0.00	0.00	0.00	0.29	0.00	0.00	2.02	0.27
Existing Investment	Distribution Pipe	Drummond St W - Eastern - Area 60 - 1142	30345	Value Driven	-	-	(843)	(877)	33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.67	0.00	0.00	0.00	0.15	0.00	0.00	1.40	0.20
Emergent	Distribution Pipe	Daniel St S - Eastern - Area 60 - 1213	30344	Value Driven	-	-	(907)	(947)	41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.76	0.00	0.00	0.00	0.29	0.00	0.00	1.30	0.19
Existing Investment	Distribution Pipe	Madawaska St - Eastern - Area 60 - 1072	30365	Value Driven	-	-	(1,200)	(1,278)	78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	74.37	0.00	0.00	0.00	0.14	0.00	0.00	3.11	0.45
Existing Investment	Distribution Pipe	Main St E - Eastern - Area 60 - 1172	30366	Value Driven	-	-	(1,143)	(1,185)	42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.63	0.00	0.00	0.00	0.05	0.00	0.00	1.93	0.26
Existing Investment	Distribution Pipe	Queen Mary St - Eastern - Area 60 - 1103	30379	Value Driven	-	-	(1,188)	(1,272)	84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	80.19	0.00	0.00	0.00	0.30	0.00	0.00	3.23	0.43
Existing Investment	Distribution Pipe	Queen St N - Eastern - Area 60 - 1158	30380	Value Driven	-	-	(1,223)	(1,292)	69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.32	0.00	0.00	0.00	0.43	0.00	0.00	2.38	0.34
Existing Investment	Distribution Pipe	TOR10YR - Parklawn - Delta North Replacement	503169	Value Driven	-	-	(472)	(472)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Centre St - Eastern - Area 60 - 1085	30343	Value Driven	-	-	(397)	(428)	31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.17	0.00	0.00	0.00	0.03	0.00	0.00	1.21	0.17
Emergent	Distribution Pipe	Regina St - Eastern - Area 60 - 1144	30381	Value Driven	-	-	(1,357)	(1,379)	22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.16	0.00	0.00	0.00	0.44	0.00	0.00	0.87	0.10
Existing Investment	Distribution Pipe	Ainsley Dr - Eastern - Area 60 - 1723	30333	Value Driven	-	-	(922)	(945)	23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.06	0.00	0.00	0.00	0.12	0.00	0.00	0.75	0.11
Existing Investment	Distribution Pipe	Ann St (MORATORIUM UNTIL 2026) - Eastern - Area 60 - 1100	30334	Value Driven	-	-	(504)	(528)	24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.77	0.00	0.00	0.00	0.03	0.00	0.00	0.98	0.14
Emergent	Distribution Pipe	Bank St (MORATORIUM UNTIL 2026) - Eastern - Area 60 - 1051	30336	Value Driven	-	-	(1,176)	(1,194)	18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.90	0.00	0.00	0.00	0.11	0.00	0.00	0.65	0.09
Existing Investment	Distribution Pipe	McCann St - Eastern - Area 60 - 1160	30367	Value Driven	-	-	(1,389)	(1,454)	64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.68	0.00	0.00	0.00	0.10	0.00	0.00	2.23	0.33
Existing Investment	Distribution Pipe	TOR10YR - Weston - Gulfstream Replacement	733682	Value Driven	-	-	(991)	(991)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	North St - Eastern - Area 60 - 1087	30372	Value Driven	-	-	(958)	(1,006)	48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	45.71	0.00	0.00	0.00	0.16	0.00	0.00	1.85	0.27
Existing Investment	Distribution Pipe	Carling Ave - Eastern - Area 60 - 1104	30342	Value Driven	-	-	(639)	(660)	21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.82	0.00	0.00	0.00	0.31	0.00	0.00	0.92	0.10
Existing Investment	Distribution Pipe	TOR10YR - Browns Line at Horner Replacement- Network # 123_368_37	733675	Value Driven	-	-	(764)	(764)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Morin St - Eastern - Area 60 - 1123	30371	Value Driven	-	-	(1,001)	(1,102)	100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	94.61	0.00	0.00	0.00	1.11	0.00	0.00	4.14	0.57
Emergent	Distribution Pipe	TOR10YR - Danube and Wayne Replacement - Network # 455	735842	Value Driven	-	-	(679)	(679)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Pr#62, NRP - 2025 - Cameron Street - Collingwood - 1616	30108	Value Driven	-	-	(297)	(304)	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.56	0.00	0.00	0.00	0.02	0.00	0.00	0.29	0.04
Existing Investment	Distribution Pipe	Brock St - Eastern - Area 60 - 1485	30341	Value Driven	-	-	(1,213)	(1,249)	36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.22	0.00	0.00	0.00	0.04	0.00	0.00	2.23	0.32
Emergent	Distribution Pipe	Riordon Ave - Eastern - Area 60 - 1102	30383	Value Driven	-	-	(903)	(939)	36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.16	0.00	0.00	0.00	0.05	0.00	0.00	1.59	0.23
Existing Investment	Distribution Pipe	Borthwick Ave (MORATORIUM UNTIL 2025) - Eastern - Area 60 - 1139	30340	Value Driven	-	-	(1,148)	(1,205)	57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	54.45	0.00	0.00	0.00	0.15	0.00	0.00	2.40	0.32
Existing Investment	Distribution Pipe	Bell St - Eastern - Area 60 - 1052	30339	Value Driven	-	-	(1,124)	(1,192)	68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	64.44	0.00	0.00	0.00	0.04	0.00	0.00	2.77	0.40
Existing Investment	Distribution Pipe	Beckwith St N - Eastern - Area 60 - 1198	30338	Value Driven	-	-	(929)	(969)	40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.10	0.00	0.00	0.00	0.15	0.00	0.00	1.68	0.24
Existing Investment	Distribution Pipe	Moffatt St - Eastern - Area 60 - 1195	30369	Value Driven	-	-	(1,147)	(1,188)	41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.60	0.00	0.00	0.00	0.12	0.00	0.00	1.43	0.20
Emergent	Distribution Pipe	Bartholomew St - Eastern - Area 60 - 1116	30337	Value Driven	-	-	(1,798)	(1,842)	44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.12	0.00	0.00	0.00	0.63	0.00	0.00	1.33	0.19
Existing Investment	Distribution Pipe	TOR10YR - Parklawn - Beta and Gamma North Replacement	503168	Value Driven	-	-	(929)	(929)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Rochester St - Eastern - Area 60 - 1222	30384	Value Driven	-	-	(1,002)	(1,056)	54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.95	0.00	0.00	0.00	0.31	0.00	0.00	1.61	0.24
Existing Investment	Distribution Pipe	TOR10YR - Weston - Verobeach and Belleglade Replacement	733683	Value Driven	-	-	(1,190)	(1,190)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Ormond St - Eastern - Area 60 - 1108	30375	Value Driven	-	-	(1,078)	(1,115)	36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.93	0.00	0.00	0.00	0.12	0.00	0.00	1.79	0.23
Existing Investment	Distribution Pipe	TOR10YR - Victoria Park Ivordale Replacement - Network # 455	735867	Value Driven	-	-	(928)	(928)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Combermere Replacement - Network # 455	735868	Value Driven	-	-	(1,545)	(1,545)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Sarah St - Eastern - Area 60 - 1188	30385	Value Driven	-	-	(962)	(1,011)	49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	47.04	0.00	0.00	0.00	0.18	0.00	0.00	1.93	0.27
Existing Investment	Distribution Pipe	TOR10YR - Parkwoods Village Replacement - Network # 455	735869	Value Driven	-	-	(1,214)	(1,214)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
Existing Investment	Distribution Pipe	VSM - Firestone Road - 2" ST - PH1	100497	Value Driven	-	-	(1,446)	(1,547)	101	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	96.55	0.00	0.00	0.00	0.08	0.00	0.00	3.46	0.49
Emergent	Distribution Pipe	VSM - Royal Group Cres	7670	Value Driven	-	$ 153,667	(956)	(1,680)	724	0.00	50.76	0.00	0.00	0.00	214.08	0.00	0.00	0.00	0.00	0.00	362.30	0.00	0.00	0.00	0.00	0.00	42.20	0.00	54.55
Existing Investment	Distribution Pipe	Summerville Ave - Eastern - Area 60 - 1484	30389	Value Driven	-	-	(1,238)	(1,306)	69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.17	0.00	0.00	0.00	0.30	0.00	0.00	2.10	0.28
Emergent	Distribution Pipe	VSM on College from Huron to Elizabeth	4109	Value Driven	-	-	(1,073)	(1,094)	21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.35	0.00	0.00	0.00	0.44	0.00	0.00	0.40	0.04
Emergent	Distribution Pipe	Park Ave - Eastern - Area 60 - 1224	30377	Value Driven	-	-	(1,128)	(1,185)	56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.94	0.00	0.00	0.00	0.18	0.00	0.00	2.02	0.31
Existing Investment	Distribution Pipe	TOR10YR - Brookbanks and Valley Woods Replacement - Network # 45	735870	Value Driven	-	-	(1,277)	(1,277)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Truxford and Overbank Replacement - Network # 455	735871	Value Driven	-	-	(904)	(904)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Herriott St - Eastern - Area 60 - 1089	30357	Value Driven	-	-	(629)	(670)	40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.59	0.00	0.00	0.00	0.08	0.00	0.00	1.45	0.21
Emergent	Distribution Pipe	AR40: VSM Replacement Wilson Rd S Oshawa Bloor St to Dieppe Ave Re	737817	Value Driven	$ 19,470	$ 606,840	(438)	(438)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Montgomery Pl - Eastern - Area 60 - 1228	30370	Value Driven	-	-	(1,253)	(1,301)	48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.10	0.00	0.00	0.00	0.23	0.00	0.00	1.82	0.26
Existing Investment	Distribution Pipe	TOR10YR - Wallingford Replacement - Network # 455	735872	Value Driven	-	-	(1,100)	(1,100)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Ogden Ave - Eastern - Area 60 - 1076	30374	Value Driven	-	-	(835)	(874)	40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.66	0.00	0.00	0.00	0.06	0.00	0.00	1.63	0.24
Emergent	Distribution Pipe	TOR10YR - Cassandra Replacement - Network # 455	735873	Value Driven	-	-	(997)	(997)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	A60: Havelock St , Brockville, VSM Replacement	30356	Value Driven	-	-	(2,687)	(2,739)	52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.62	0.00	0.00	0.00	0.08	0.00	0.00	2.48	0.36
Emergent	Distribution Pipe	Hamilton St - Eastern - Area 60 - 1056	30355	Value Driven	-	-	(1,147)	(1,222)	75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.56	0.00	0.00	0.00	0.58	0.00	0.00	2.42	0.34
Existing Investment	Distribution Pipe	Grant St - Eastern - Area 60 - 1098	30354	Value Driven	-	-	(920)	(961)	42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.47	0.00	0.00	0.00	0.09	0.00	0.00	1.81	0.25
Emergent	Distribution Pipe	Sherbrooke St E - Eastern - Area 60 - 1081	30386	Value Driven	-	-	(742)	(807)	65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.75	0.00	0.00	0.00	0.08	0.00	0.00	2.92	0.41
Emergent	Distribution Pipe	Baseline Rd E-Whitby-1182	30177	Value Driven	-	-	(1,328)	(1,381)	53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.35	0.00	0.00	0.00	0.10	0.00	0.00	2.24	0.31
Emergent	Distribution Pipe	Gore St W - Eastern - Area 60 - 1097	30353	Value Driven	-	-	(877)	(919)	42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.84	0.00	0.00	0.00	0.06	0.00	0.00	1.87	0.27
Existing Investment	Distribution Pipe	George St - Eastern - Area 60 - 1088	30352	Value Driven	-	-	(660)	(727)	67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	63.84	0.00	0.00	0.00	0.06	0.00	0.00	2.72	0.38
Existing Investment	Distribution Pipe	Flora St - Eastern - Area 60 - 1151	30351	Value Driven	-	-	(869)	(912)	44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.95	0.00	0.00	0.00	0.12	0.00	0.00	1.49	0.21
Existing Investment	Distribution Pipe	First Ave - Eastern - Area 60 - 1175	30350	Value Driven	-	-	(1,261)	(1,299)	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.61	0.00	0.00	0.00	0.09	0.00	0.00	1.85	0.26
Emergent	Distribution Pipe	TOR10YR - Underhill Replacement - Network # 455	735874	Value Driven	-	-	(1,361)	(1,361)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	TOR10YR - Avonwick Gate and Beveridge Replacement - Network # 455	735875	Value Driven	-	-	(946)	(946)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Caddy St-Peterborough-1179	30178	Value Driven	-	-	(1,389)	(1,441)	51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.82	0.00	0.00	0.00	0.06	0.00	0.00	2.23	0.32
Existing Investment	Distribution Pipe	Emily St - Eastern - Area 60 - 1101	30349	Value Driven	-	-	(1,120)	(1,164)	44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.94	0.00	0.00	0.00	0.09	0.00	0.00	1.66	0.26
Emergent	Distribution Pipe	TOR10YR - Castlegrove Replacement - Network # 455	735876	Value Driven	-	-	(1,617)	(1,617)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Elmsley St N - Eastern - Area 60 - 1725	30348	Value Driven	-	-	(635)	(674)	39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.37	0.00	0.00	0.00	0.17	0.00	0.00	1.36	0.21
Existing Investment	Distribution Pipe	Christena Cres 1 - Ajax - Area 40 - 1702	30179	Value Driven	-	-	(1,299)	(1,345)	46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.78	0.00	0.00	0.00	0.19	0.00	0.00	1.73	0.25
Existing Investment	Distribution Pipe	TOR10YR - Tiffany and Woodthorpe Replacement - Network # 455	735864	Value Driven	-	-	(416)	(416)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	HR - 1040 Bridletowne Circle	100506	Value Driven	-	$ 19,208	2,542	(297)	2,839	0.00	36.56	0.00	180.22	0.06	154.20	0.00	123.51	0.00	0.00	0.00	658.73	0.00	0.00	0.00	0.00	0.00	422.00	1,235.12	28.30
Emergent	Distribution Pipe	Christena Cres 2 - Ajax - Area 40 - 1704	30180	Value Driven	-	-	(932)	(968)	35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.49	0.00	0.00	0.00	0.08	0.00	0.00	1.57	0.22
Existing Investment	Distribution Pipe	TOR10YR - Elvaston Replacement - Network # 455	735858	Value Driven	-	-	(958)	(958)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Elm St W - Eastern - Area 60 - 1726	30347	Value Driven	-	-	(462)	(481)	19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.28	0.00	0.00	0.00	0.13	0.00	0.00	0.56	0.08
Existing Investment	Distribution Pipe	TOR10YR - Bellman to N Carson Replacement- Network # 123_368_373	733666	Value Driven	-	-	(1,046)	(1,046)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Anewen and Kenewen Replacement - Network # 455	735865	Value Driven	-	-	(569)	(569)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	TOR10YR - Broadlands Replacement - Network # 455	735877	Value Driven	-	-	(1,660)	(1,660)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	TOR10YR - Roanoke Replacement - Network # 455	735878	Value Driven	-	-	(633)	(633)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	TOR10YR - Cornerbrook and Redwillow Replacement - Network # 455	735879	Value Driven	-	-	(1,364)	(1,364)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Pr#61, NRP - 2028 - Third Street - Collingwood - 1618	30107	Value Driven	-	-	(170)	(179)	10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.12	0.00	0.00	0.00	0.03	0.00	0.00	0.41	0.06
Existing Investment	Distribution Pipe	TOR10YR - North Sloane Replacement - Network # 455	735860	Value Driven	-	-	(1,348)	(1,348)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	TOR10YR - Railside and Lawrence Replacement - Network # 455	735880	Value Driven	-	-	(194)	(194)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	TOR10YR - Deanvar and Glasworthy Replacement - Network # 455	735881	Value Driven	-	-	(538)	(538)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Pharmacy and Dewey Replacement - Network # 455	735866	Value Driven	-	-	(660)	(660)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Colingwood and Dempster Replacement - Network # 455	735839	Value Driven	-	-	(1,014)	(1,014)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Browns Line and Jellicoe Replacement- Network # 123 368	733910	Value Driven	-	-	(1,869)	(1,869)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Pr#60, NRP - 2024 - High Street - Collingwood - 1615	30106	Value Driven	-	-	(1,605)	(1,614)	9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.53	0.00	0.00	0.00	0.04	0.00	0.00	0.18	0.02
Emergent	Distribution Pipe	VSM - Firestone Road - 2" ST - Eastside	739942	Value Driven	-	$ 484,366	(339)	(339)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Wilson St E - Eastern - Area 60 - 1094	30394	Value Driven	-	-	(740)	(832)	92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	87.70	0.00	0.00	0.00	0.07	0.00	0.00	3.77	0.56
Emergent	Distribution Pipe	TOR10YR - Lawrence and Warden East Replacement - Network # 455	735845	Value Driven	-	-	(620)	(620)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Windsor Dr-Ajax-1193	30196	Value Driven	-	-	(1,032)	(1,075)	43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.46	0.00	0.00	0.00	0.03	0.00	0.00	2.09	0.25
Existing Investment	Distribution Pipe	Welland St PTC- Area 80 - 1173	30080	Value Driven	-	-	(496)	(507)	11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.65	0.00	0.00	0.00	0.00	0.00	0.00	0.57	0.09
Emergent	Distribution Pipe	TOR10YR - Lawrence at Wayne Replacement - Network # 455	735844	Value Driven	-	-	(2,190)	(2,190)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	3665 Flamewood Replacement Copper Relay	736516	Value Driven	$ 13	$ 448,195	(313)	(313)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Vista Dr_GTA West_Area 20_1529	30132	Value Driven	-	-	(1,609)	(1,711)	102	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	96.90	0.00	0.00	0.00	0.37	0.00	0.00	4.15	0.59
Emergent	Distribution Pipe	William St (MORATORIUM UNTIL 2027)_GTA West_Area 20_1190	30133	Value Driven	-	-	(702)	(748)	46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.69	0.00	0.00	0.00	0.14	0.00	0.00	2.28	0.28
Emergent	Distribution Pipe	TOR10YR - Warden South Lawrence Replacement - Network # 455	735843	Value Driven	-	-	(2,241)	(2,241)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Riddell Ave S (MORATORIUM UNTIL 2026) - Eastern - Area 60 - 1225	30382	Value Driven	-	-	(1,077)	(1,102)	25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.96	0.00	0.00	0.00	0.05	0.00	0.00	1.23	0.15
Emergent	Distribution Pipe	Avondale Blvd 1 - GTA West - Area 20 - 1663	30112	Value Driven	-	-	(1,249)	(1,307)	58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	54.53	0.00	0.00	0.00	0.04	0.00	0.00	3.12	0.44
Existing Investment	Distribution Pipe	Rupert Ave - GTA East - Area 30 - 1815	30170	Value Driven	-	-	(2,124)	(2,180)	57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	54.42	0.00	0.00	0.00	0.19	0.00	0.00	1.83	0.27
Existing Investment	Distribution Pipe	Ruggles Ave - GTA East - Area 30 - 1706	30169	Value Driven	-	-	(1,428)	(1,491)	63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.61	0.00	0.00	0.00	0.20	0.00	0.00	2.51	0.35
Emergent	Distribution Pipe	Avondale Blvd 2 - GTA West - Area 20 - 1664	30113	Value Driven	-	-	(1,377)	(1,444)	67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.65	0.00	0.00	0.00	0.14	0.00	0.00	4.54	0.65
No Longer in Plan	Distribution Pipe	VSM - Bromsgrove Header	7655	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Broadway_GTA West_Area 20_1249	30114	Value Driven	-	-	(1,316)	(1,358)	43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.65	0.00	0.00	0.00	0.24	0.00	0.00	1.78	0.24
Existing Investment	Distribution Pipe	Clarkson Rd (EXECUTE 2025 - ROAD REHABILITATION WORK PLANNED F	30115	Value Driven	-	-	(1,830)	(1,888)	58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.68	0.00	0.00	0.00	0.25	0.00	0.00	1.88	0.27
Existing Investment	Distribution Pipe	Othello Ave - Eastern - Area 60 - 1096	30376	Value Driven	-	-	(541)	(569)	27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.90	0.00	0.00	0.00	0.06	0.00	0.00	1.17	0.14
Existing Investment	Distribution Pipe	TOR10YR - Birchmount & Foxbridge Replacement - Network # 277	735487	Value Driven	-	-	(1,236)	(1,236)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Elizabeth St S 1 - GTA West - Area 20 - 1667	30117	Value Driven	-	-	(1,311)	(1,375)	64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.77	0.00	0.00	0.00	0.45	0.00	0.00	2.20	0.29
Existing Investment	Distribution Pipe	Elizabeth St S 2 - GTA West - Area 20 - 1668	30118	Value Driven	-	-	(1,268)	(1,324)	56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.68	0.00	0.00	0.00	0.28	0.00	0.00	2.25	0.30
Emergent	Distribution Pipe	Frederick_GTA West_Area 20_1481	30119	Value Driven	-	-	(1,346)	(1,422)	75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.89	0.00	0.00	0.00	0.32	0.00	0.00	2.77	0.38
Existing Investment	Distribution Pipe	Gordon St_GTA West_Area 20_1227	30120	Value Driven	-	-	(1,173)	(1,218)	45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.26	0.00	0.00	0.00	0.03	0.00	0.00	1.82	0.25
Existing Investment	Distribution Pipe	Haggert Ave_GTA West_Area 20_1477	30121	Value Driven	-	-	(1,959)	(2,024)	65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	62.41	0.00	0.00	0.00	0.29	0.00	0.00	2.38	0.34
Existing Investment	Distribution Pipe	Ashlar Rd - GTA East - Area 30 - 1841	30162	Value Driven	-	-	(1,395)	(1,478)	83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	77.70	0.00	0.00	0.00	0.08	0.00	0.00	4.97	0.69
No Longer in Plan	Distribution Pipe	VSM - Preston St - LP	8262	Value Driven	-	-	(1,858)	(1,980)	122	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	3.06	0.00	0.00	0.00	0.00	0.00	3.91	114.31	0.81
Existing Investment	Distribution Pipe	Axminster Dr - GTA East - Area 30 - 1842	30163	Value Driven	-	-	(2,182)	(2,261)	79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.60	0.00	0.00	0.00	0.07	0.00	0.00	4.46	0.63
Existing Investment	Distribution Pipe	Church St South_2 - GTA East - Area 30 - 1382	30164	Value Driven	-	-	(2,606)	(2,756)	149	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	146.21	0.00	0.00	0.00	1.73	0.00	0.00	0.99	0.13
Emergent	Distribution Pipe	Colborne Ave - GTA East - Area 30 - 1705	30165	Value Driven	-	-	(696)	(741)	44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.86	0.00	0.00	0.00	0.10	0.00	0.00	2.22	0.29
Existing Investment	Distribution Pipe	Dunning Ave - GTA East - Area 30 - 1710	30166	Value Driven	-	-	(848)	(876)	29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.08	0.00	0.00	0.00	0.06	0.00	0.00	1.39	0.16
Existing Investment	Distribution Pipe	Elgin Mills Rd E - GTA East - Area 30 - 1351	30167	Value Driven	-	-	(3,096)	(3,186)	90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86.58	0.00	0.00	0.00	1.36	0.00	0.00	1.61	0.23
Existing Investment	Distribution Pipe	Victoria St - Eastern - Area 60 - 1138	30391	Value Driven	-	-	(896)	(926)	30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.84	0.00	0.00	0.00	0.03	0.00	0.00	1.20	0.17
Existing Investment	Distribution Pipe	Wellington St - GTA East - Area 30 - 1417	30174	Value Driven	-	-	(1,582)	(1,649)	67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	63.73	0.00	0.00	0.00	0.24	0.00	0.00	2.30	0.32
Existing Investment	Distribution Pipe	Tecumseth St - GTA East - Area 30 - 1362	30173	Value Driven	-	-	(1,677)	(1,792)	115	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	109.49	0.00	0.00	0.00	0.26	0.00	0.00	4.31	0.61
Existing Investment	Distribution Pipe	Taylor Mills Dr S - GTA East - Area 30 - 1843	30172	Value Driven	-	-	(1,288)	(1,347)	58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.40	0.00	0.00	0.00	0.28	0.00	0.00	2.06	0.29
No Longer in Plan	Distribution Pipe	A80: Lundys Lane Reg. Rd 20 Niagara Falls, VS Replacement	503325	Value Driven	-	-	(368)	(379)	11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.33	0.00	0.00	0.00	6.10	0.00	0.00	0.00	0.00	0.00	3.91	0.00	1.10
Existing Investment	Distribution Pipe	A60: Sparks St, Ottawa, Replacement	101343	Value Driven	$ 99,944	$ 128,056	(5,601)	(8,801)	3,200	0.00	0.96	0.00	2,744.51	0.00	4.03	0.00	0.00	0.00	0.00	0.00	310.34	0.00	0.00	0.00	0.00	0.00	0.04	105.80	34.12
Existing Investment	Distribution Pipe	TOR10YR - Willowmount & Birchmount Replacement - Network # 277	735489	Value Driven	-	-	(897)	(897)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Dexter Dr WELL - Area 80 - 1169	30050	Value Driven	-	-	(1,452)	(1,496)	44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.07	0.00	0.00	0.00	0.17	0.00	0.00	1.61	0.23
Emergent	Distribution Pipe	NPS20 KOL - Parliament St.	740604	Value Driven	$ 13,131,787	-	(9,769)	(9,769)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	TOR10YR - Goldsmith and Townley Replacement - Network # 455	735882	Value Driven	-	-	(541)	(541)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	VSM - Yonge and Davis Dr West - Phase2	502190	Value Driven	-	-	(1,062)	(1,169)	107	0.00	1.68	0.00	0.00	1.42	7.09	0.00	0.00	0.00	0.00	0.72	21.06	0.00	0.00	0.00	0.00	0.00	2.45	71.79	0.62
Emergent	Distribution Pipe	TOR10YR - Pharmacy North Lawrence Replacement - Network # 455	735883	Value Driven	-	-	(639)	(639)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Durham St W - Kawartha Lakes - Area 40 - 1687	30181	Value Driven	-	-	(1,879)	(1,942)	63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.70	0.00	0.00	0.00	0.68	0.00	0.00	2.21	0.31
No Longer in Plan	Distribution Pipe	HR - 200-250 Bridletowne Circle	100505	Value Driven	-	-	2,359	(296)	2,655	0.00	36.56	0.00	180.22	0.06	154.20	0.00	114.31	0.00	0.00	0.00	609.67	0.00	0.00	0.00	0.00	0.00	390.57	1,143.13	26.20
Existing Investment	Distribution Pipe	NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.	11443	Value Driven	-	-	(17,574)	(17,726)	153	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.58	0.00	0.00	1.06	31.03	0.00	0.00	0.00	0.00	0.00	0.31	105.80	3.75
Emergent	Distribution Pipe	TOR10YR - Lawrence Ave E at Pharmacy Replacement - Network # 455	735884	Value Driven	-	-	(2,396)	(2,396)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Howard Ave 1 - Kawartha Lakes - Area 40 - 1692	30183	Value Driven	-	-	(459)	(476)	17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.90	0.00	0.00	0.00	0.01	0.00	0.00	0.94	0.13
Emergent	Distribution Pipe	TOR10YR - Elinor Replacement - Network # 455	735885	Value Driven	-	-	(915)	(915)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Highgate Rd - Eastern - Area 60 - 1166	30358	Value Driven	-	-	(542)	(556)	14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.31	0.00	0.00	0.00	0.01	0.00	0.00	0.56	0.08
Existing Investment	Distribution Pipe	TOR10YR - Parklawn - Lanor and Valermo Replacement	503167	Value Driven	-	-	(1,000)	(1,000)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
Existing Investment	Distribution Pipe	Spring St - Eastern - Area 60 - 1047	30387	Value Driven	-	-	(889)	(928)	39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.11	0.00	0.00	0.00	0.13	0.00	0.00	1.32	0.19
Existing Investment	Distribution Pipe	A10: Wilson Avenue, Toronto, VSM Replacement	100339	Value Driven	-	-	(60,709)	(61,281)	573	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	529.83	0.00	0.00	0.00	38.84	0.00	0.00	3.64	0.44
Existing Investment	Distribution Pipe	Euclid Ave-Peterborough-1106	30182	Value Driven	-	-	(1,646)	(1,687)	41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.70	0.00	0.00	0.00	0.10	0.00	0.00	1.70	0.24
Emergent	Distribution Pipe	TOR10YR - Gooderham Replacement - Network # 455	735886	Value Driven	-	-	(1,029)	(1,029)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	TOR10YR - Warden West Replacement - Network # 455	735887	Value Driven	-	-	(951)	(951)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	TOR10YR - Tower and Timgren Replacement - Network # 455	735888	Value Driven	-	-	(695)	(695)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	A10: Kipling Ave & Lake Shore Blvd W, Etobicoke, PH2 Replacement	7604	Value Driven	$ 19,470	$ 468,560	5,569	(342)	5,911	0.00	90.45	0.00	0.00	1,038.41	381.51	0.00	133.45	0.00	0.00	0.00	711.71	0.00	0.00	0.00	0.00	0.00	455.94	2,668.91	430.36
Existing Investment	Distribution Pipe	TOR10YR - Sweeney Replacement - Network # 455	735861	Value Driven	-	-	(1,933)	(1,933)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Howard Ave 2 - Kawartha Lakes - Area 40 - 1694	30184	Value Driven	-	-	(666)	(682)	15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.43	0.00	0.00	0.00	0.04	0.00	0.00	0.72	0.10
Existing Investment	Distribution Pipe	TOR10YR - Knighton and Prestbury Replacement - Network # 455	735862	Value Driven	-	-	(1,329)	(1,329)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Stanley Ave - Eastern - Area 60 - 1069	30388	Value Driven	-	-	(651)	(687)	36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.56	0.00	0.00	0.00	0.06	0.00	0.00	1.12	0.15
Existing Investment	Distribution Pipe	Market St - Area 50 - 1221	30088	Value Driven	-	-	(1,073)	(1,121)	48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	45.79	0.00	0.00	0.00	0.15	0.00	0.00	1.94	0.28
Existing Investment	Distribution Pipe	TOR10YR - Wigmore and Draycott Replacement - Network # 455	735857	Value Driven	-	-	(1,128)	(1,128)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Eccleston and Tinder Replacement - Network # 455	735859	Value Driven	-	-	(819)	(819)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Savona and Bisset Replacement- Network # 123_368_373	733668	Value Driven	-	-	(851)	(851)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Silvercrest to Aldercrest Replacement- Network # 123_368_3	733664	Value Driven	-	-	(320)	(320)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Parklawn - Aldercrest to Lunness North Replacement	733447	Value Driven	-	-	(1,093)	(1,093)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Evans Ave Replacement- Network # 123_368_373	733448	Value Driven	-	-	(1,228)	(1,228)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Toronto Island NPS 2 Feed Relocation	23147	Value Driven	-	$ 25,611	(2,092)	(2,501)	410	0.00	0.45	0.00	0.00	0.00	1.89	0.00	0.00	0.00	0.00	0.00	362.30	0.00	0.00	0.00	0.00	0.00	36.02	0.00	8.94
Emergent	Distribution Pipe	Whitton Crescent - Eastern - Area 60 - 1140	30392	Value Driven	-	-	(1,185)	(1,291)	105	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.40	0.00	0.00	0.00	0.26	0.00	0.00	4.17	0.54
Emergent	Distribution Pipe	William St N - Kawartha Lakes - Area 40 - 1816	30195	Value Driven	$ -	$ -	(2,065)	(2,086)	21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.29	0.00	0.00	0.00	0.02	0.00	0.00	0.79	0.11
Existing Investment	Distribution Pipe	TOR10YR - Sloane and Ruscica Replacement - Network # 455	735856	Value Driven	-	-	(1,076)	(1,076)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Albright and Roseland Replacement- Network # 123_368_37	733679	Value Driven	-	-	(984)	(984)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Browns Evans Gair Replacement- Network # 123_368_373	733667	Value Driven	-	-	(684)	(684)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Foxbridge-Roebuck Replacement - Network # 277	735485	Value Driven	-	-	(898)	(898)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Roywood and York Mills Replacement - Network # 455	735855	Value Driven	-	-	(1,802)	(1,802)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Fenside and Lynedock Replacement - Network # 455	735854	Value Driven	-	-	(2,129)	(2,129)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	121 – 151 L'Amoreaux Dr Steel Header Replacements	7651	Value Driven	-	-	2,294	(361)	2,655	0.00	36.56	0.00	180.22	0.06	154.20	0.00	114.31	0.00	0.00	0.00	609.67	0.00	0.00	0.00	0.00	0.00	390.57	1,143.13	26.20
Existing Investment	Distribution Pipe	HR - 201 Bridletowne Circle	7649	Value Driven	$ 19,470	$ 19,208	2,735	(104)	2,839	0.00	36.56	0.00	180.22	0.06	154.20	0.00	123.51	0.00	0.00	0.00	658.73	0.00	0.00	0.00	0.00	0.00	422.00	1,235.12	28.30
No Longer in Plan	Distribution Pipe	HR - 1021 Midland Ave	7647	Value Driven	-	-	2,445	(210)	2,655	0.00	36.56	0.00	180.22	0.06	154.20	0.00	114.31	0.00	0.00	0.00	609.67	0.00	0.00	0.00	0.00	0.00	390.57	1,143.13	26.20
Existing Investment	Distribution Pipe	Paliser Cres S - GTA East - Area 30 - 1389	30168	Value Driven	-	-	(1,360)	(1,467)	107	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	102.92	0.00	0.00	0.00	0.57	0.00	0.00	3.35	0.48
No Longer in Plan	Distribution Pipe	HR - 160-260 Chester Lee Blvd	7646	Value Driven	-	-	(285)	(801)	516	0.00	85.29	0.00	0.00	0.00	359.75	0.00	0.03	0.00	0.00	0.00	30.51	0.00	0.00	0.00	0.00	0.00	39.06	0.00	1.84
Existing Investment	Distribution Pipe	Queen St S 1 (EXECUTE 2026 - ROAD REHABILITATION WORK PLANNED	30126	Value Driven	-	-	(1,041)	(1,079)	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.09	0.00	0.00	0.00	0.14	0.00	0.00	1.51	0.22
Existing Investment	Distribution Pipe	Wellington St - Kawartha Lakes - Area 40 - 1678	30194	Value Driven	-	-	(1,555)	(1,597)	42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.15	0.00	0.00	0.00	0.25	0.00	0.00	1.41	0.20
Existing Investment	Distribution Pipe	Tulloch Dr-Ajax-1594	30193	Value Driven	-	-	(1,524)	(1,614)	89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	83.77	0.00	0.00	0.00	0.12	0.00	0.00	4.75	0.68
Existing Investment	Distribution Pipe	Simcoe Street-40-Kawartha Lakes-1060	30192	Value Driven	-	-	(1,344)	(1,396)	52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.41	0.00	0.00	0.00	0.06	0.00	0.00	2.40	0.34
Emergent	Distribution Pipe	Russel St W-Kawartha Lakes-1105	30191	Value Driven	-	-	(799)	(842)	42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.06	0.00	0.00	0.00	0.07	0.00	0.00	1.96	0.28
Existing Investment	Distribution Pipe	Main St (EXECUTE 2024 - STREETSCAPE PLANNED FOR 2023 2024) GTA	30125	Value Driven	-	-	(1,664)	(1,725)	61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.31	0.00	0.00	0.00	0.23	0.00	0.00	2.46	0.32
Existing Investment	Distribution Pipe	Regent St - Kawartha Lakes - Area 40 - 1697	30190	Value Driven	-	-	(410)	(428)	18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.36	0.00	0.00	0.00	0.04	0.00	0.00	0.71	0.10
Emergent	Distribution Pipe	Lewisham Dr_GTA West_Area 20_1146	30124	Value Driven	-	-	(1,173)	(1,455)	282	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	268.68	0.00	0.00	0.00	0.05	0.00	0.00	11.64	1.63
Existing Investment	Distribution Pipe	Joymar Dr 2 (EXECUTE 2024 - ROAD REHABILITATION WORK PLANNED	30123	Value Driven	-	-	(1,497)	(1,541)	45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.28	0.00	0.00	0.00	0.14	0.00	0.00	2.15	0.30
Existing Investment	Distribution Pipe	Sproule Dr 2 - GTA West - Area 20 - 1677	30131	Value Driven	-	-	(1,098)	(1,125)	27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.46	0.00	0.00	0.00	0.11	0.00	0.00	1.03	0.14
Existing Investment	Distribution Pipe	Seagull Dr 2 - GTA West - Area 20 - 1675	30129	Value Driven	-	-	(1,422)	(1,479)	57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.19	0.00	0.00	0.00	0.08	0.00	0.00	3.21	0.41
Existing Investment	Distribution Pipe	Joymar Dr 1 (EXECUTE 2024 - ROAD REHABILITATION WORK PLANNED	30122	Value Driven	-	-	(1,374)	(1,419)	44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.70	0.00	0.00	0.00	0.07	0.00	0.00	2.36	0.31
Existing Investment	Distribution Pipe	Z74, NRP - HNS Queens Park B, 2023 - 2025 - 1652	30111	Value Driven	-	-	(1,080)	(1,133)	53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.61	0.00	0.00	0.00	0.32	0.00	0.00	2.12	0.29
Existing Investment	Distribution Pipe	Pine St - Area 50 - 1205	30091	Value Driven	-	-	(1,035)	(1,107)	72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	68.48	0.00	0.00	0.00	0.29	0.00	0.00	2.52	0.38
Existing Investment	Distribution Pipe	Prospect St-Bowmanville-1086	30189	Value Driven	-	-	(551)	(581)	30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.23	0.00	0.00	0.00	0.01	0.00	0.00	1.24	0.18
Existing Investment	Distribution Pipe	Sproule Dr 1 - GTA West - Area 20 - 1676	30130	Value Driven	-	-	(1,405)	(1,481)	76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	72.43	0.00	0.00	0.00	0.76	0.00	0.00	2.37	0.32
Existing Investment	Distribution Pipe	Seagull Dr 1 - GTA West - Area 20 - 1674	30128	Value Driven	-	-	(1,177)	(1,240)	64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.58	0.00	0.00	0.00	0.42	0.00	0.00	2.28	0.30
Existing Investment	Distribution Pipe	Queen St S 2 (EXECUTE 2026 - ROAD REHABILITATION WORK PLANNED	30127	Value Driven	-	-	(791)	(830)	39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.70	0.00	0.00	0.00	0.20	0.00	0.00	1.44	0.21
Existing Investment	Distribution Pipe	Prince St-Bowmanville-1846	30188	Value Driven	-	-	(1,448)	(1,501)	53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.39	0.00	0.00	0.00	0.09	0.00	0.00	2.31	0.30
Existing Investment	Distribution Pipe	Poplar Ave 2 - Ajax - Area 40 - 1681	30187	Value Driven	-	-	(1,077)	(1,089)	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.32	0.00	0.00	0.00	0.01	0.00	0.00	0.50	0.07
Existing Investment	Distribution Pipe	Poplar Ave 1 - Ajax - Area 40 - 1680	30186	Value Driven	-	-	(1,669)	(1,716)	47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.79	0.00	0.00	0.00	0.02	0.00	0.00	1.81	0.26
Existing Investment	Distribution Pipe	TOR10YR - Parklawn A1 D - Beta and Aldercrest Replacement	503161	Value Driven	$ 2,726	-	(988)	(988)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Parklawn -A1 B-Delta Replacement	503160	Value Driven	$ 519	-	(816)	(816)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Parklawn - A1 E-Alderbrae and Hallmark Replacement	503159	Value Driven	-	-	(633)	(633)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Parklawn - Parklawn A1 F-Sheldon and Lunness Replacemen	503158	Value Driven	-	-	(874)	(874)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Parklawn - Parklawn A1 C-Gamma Replacement	503156	Value Driven	$ 519	-	(725)	(725)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Bayford to Dubray Replacement Standardization - Network	502935	Value Driven	-	-	(709)	(709)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Dubray to Cornelius Replacement Standardization - Networl	502933	Value Driven	-	-	(362)	(362)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Toro to Cataford Replacement Standardization - Network #	502932	Value Driven	-	-	(665)	(665)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Keelesgate and Cuffley Replacement Standardization - Netw	502929	Value Driven	-	-	(745)	(745)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Sunset and Burlington Replacement- Network # 123_368_37	733678	Value Driven	-	-	(883)	(883)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Weston - Verobeach and Palms Replacement	733799	Value Driven	-	-	(502)	(502)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Weston - Coral Gable Replacement	733800	Value Driven	-	-	(1,013)	(1,013)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Weston - Bradstock to Verobeach Replacement	733801	Value Driven	-	-	(188)	(188)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Lilac and Griffith Replacement Standardization - Network # 1	733802	Value Driven	-	-	(749)	(749)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Westin and Jasmine Replacement Standardization - Network	733803	Value Driven	-	-	(583)	(583)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Yorkdale and Wallasey Replacement Standardization - Netwo	733804	Value Driven	-	-	(948)	(948)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Starview and Weston Replacement Standardization - Networ	733805	Value Driven	-	-	(966)	(966)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Gaydon and Highbury Replacement Standardization - Netwo	733806	Value Driven	-	-	(1,045)	(1,045)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	30: VSM - Major Mackenzie, Cedar to Newkirk, Replacement	103420	Value Driven	-	-	14,129	(1,565)	15,694	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	114.31	3,353.19	0.00	0.00	0.00	0.00	0.00	390.57	11,431.35	404.86
Existing Investment	Distribution Pipe	Z1193, NRP - HNS Brock Park B, 2024 - 2025 - 1613	30110	Value Driven	-	-	(1,011)	(1,049)	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.08	0.00	0.00	0.00	0.23	0.00	0.00	1.43	0.21
Existing Investment	Distribution Pipe	TOR10YR - Bertrand and Birchmount Replacement - Network # 455	735498	Value Driven	-	-	(649)	(649)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Eltham and Delma Replacement- Network # 123_368_373	733674	Value Driven	-	-	(952)	(952)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	King Street-40-Peterborough-1064	30185	Value Driven	-	-	(1,542)	(1,613)	71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	68.95	0.00	0.00	0.00	0.43	0.00	0.00	1.90	0.20
Existing Investment	Distribution Pipe	TOR10YR - Mitcham and Fulham Replacement - Network # 123_368_37	733673	Value Driven	-	-	(942)	(942)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Summer St NFalls- Area 80 - 1137	30077	Value Driven	-	-	(676)	(692)	16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.76	0.00	0.00	0.00	0.01	0.00	0.00	0.79	0.12
Existing Investment	Distribution Pipe	Prince Albert St - Eastern - Area 60 - 1099	30378	Value Driven	-	-	(857)	(1,083)	226	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	215.10	0.00	0.00	0.00	0.24	0.00	0.00	9.60	1.32
Existing Investment	Distribution Pipe	TOR10YR - Fenelon and Graydon Hall Replacement - Network # 455	735853	Value Driven	-	-	(683)	(683)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Pr#58, NRP - 2023 - High Street - Collingwood - 1653	30105	Value Driven	-	-	(892)	(901)	9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.80	0.00	0.00	0.00	0.31	0.00	0.00	0.25	0.04
Existing Investment	Distribution Pipe	TOR10YR - Foch and Woodbury Replacement- Network # 123_368_373	733680	Value Driven	-	-	(896)	(896)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Horner and Orianna Replacement- Network # 123_368_373	733672	Value Driven	-	-	(549)	(549)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Pr#57, NRP - 2024 - Collins Street - Collingwood - 1614	30104	Value Driven	-	-	(288)	(301)	13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.87	0.00	0.00	0.00	0.10	0.00	0.00	0.43	0.06
Existing Investment	Distribution Pipe	TOR10YR - Delma and Ecker Replacement- Network # 123_368_373	733669	Value Driven	-	-	(902)	(902)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	30: VSM - Major Mackenzie, Sussex To Newkirk, Replacement	103419	Value Driven	-	$ 1,741,559	17,105	(1,216)	18,321	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	133.45	3,914.40	0.00	0.00	0.00	0.00	0.00	455.94	13,344.55	472.62
Existing Investment	Distribution Pipe	TOR10YR - Westhead Replacement- Network # 123_368_373	733670	Value Driven	-	-	(888)	(888)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Araman and Earlton Replacement - Network # 455	735836	Value Driven	-	-	(1,391)	(1,391)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	000725, NRP - HNS Grove B2, 2028 - 2030 - 1608	30103	Value Driven	-	-	(575)	(612)	37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.28	0.00	0.00	0.00	0.21	0.00	0.00	1.24	0.17
Existing Investment	Distribution Pipe	000724, NRP - HNS Grove B1, 2030 - 2032 - 1605	30102	Value Driven	-	-	(540)	(573)	32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.56	0.00	0.00	0.00	0.14	0.00	0.00	1.31	0.18
Existing Investment	Distribution Pipe	000715, NRP - Wellington B - 2031 - 2033 - 1604	30101	Value Driven	-	-	(960)	(1,001)	41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.11	0.00	0.00	0.00	0.30	0.00	0.00	1.33	0.19
Existing Investment	Distribution Pipe	TOR10YR - Treverton & Stratton Replacement - Network # 455	735491	Value Driven	-	-	(744)	(744)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	McCain St PTC - Area 80 - 1136	30064	Value Driven	-	-	(856)	(879)	23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.69	0.00	0.00	0.00	0.03	0.00	0.00	1.17	0.17
Existing Investment	Distribution Pipe	TOR10YR - Allanford and Pender Replacement - Network # 455	735835	Value Driven	-	-	(1,391)	(1,391)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Moorecroft and Sedgewick Replacement - Network # 455	735495	Value Driven	-	-	(740)	(740)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TOR10YR - Moraine Hill and Sunmount Replacement - Network # 455	735824	Value Driven	-	-	(1,438)	(1,438)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	000088, NRP - HNS Grove A2, 2028 - 2030 - 1611	30100	Value Driven	-	-	(873)	(924)	51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.86	0.00	0.00	0.00	0.30	0.00	0.00	1.83	0.26
Existing Investment	Distribution Pipe	000071, NRP - Wellington D2 - 2023 - 2025 - 1651	30099	Value Driven	-	-	(351)	(365)	14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.78	0.00	0.00	0.00	0.09	0.00	0.00	0.53	0.06
Emergent	Distribution Pipe	000046, NRP - HNS Grove A1, 2025 - 2027 - 1612	30098	Value Driven	-	-	(1,968)	(2,038)	70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.16	0.00	0.00	0.00	0.68	0.00	0.00	2.40	0.32

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
Existing Investment	Distribution Pipe	Niagara Wine Route 2 NOTL- Area 80 - 1191	30067	Value Driven	-	-	(773)	(786)	13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.22	0.00	0.00	0.00	0.01	0.00	0.00	0.55	0.08
Existing Investment	Distribution Pipe	NPS 10 Glenridge Avenue, St. Catharines	1938	Value Driven	-	-	(8,599)	(9,437)	838	0.00	47.10	0.00	0.00	0.00	198.67	0.00	11.43	0.00	0.00	0.00	335.32	0.00	0.00	0.00	0.00	0.00	39.06	114.31	92.26
Existing Investment	Distribution Pipe	TOR10YR - Browns and Finsbury Replacement- Network # 123 368 373	733671	Value Driven	-	-	(908)	(908)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Hixon St LINC - Area 80 - 1153	30058	Value Driven	-	-	(705)	(738)	33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.39	0.00	0.00	0.00	0.03	0.00	0.00	1.52	0.22
Existing Investment	Distribution Pipe	Yonge St - Area 50 - 1206	30097	Value Driven	-	-	(1,108)	(1,146)	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.29	0.00	0.00	0.00	0.13	0.00	0.00	1.74	0.24
Emergent	Distribution Pipe	Tiffen St - Area 50 - 1212	30096	Value Driven	-	-	(774)	(828)	54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.92	0.00	0.00	0.00	0.25	0.00	0.00	2.23	0.31
Emergent	Distribution Pipe	Sunnidale St - Area 50 - 1219	30095	Value Driven	-	-	(876)	(906)	30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.19	0.00	0.00	0.00	0.10	0.00	0.00	1.13	0.16
Existing Investment	Distribution Pipe	Erie St STC - Area 80 - 1159	30052	Value Driven	-	-	(659)	(678)	20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.70	0.00	0.00	0.00	0.08	0.00	0.00	0.72	0.10
Existing Investment	Distribution Pipe	St Paul St - Area 50 - 1220	30094	Value Driven	-	-	(911)	(946)	35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.51	0.00	0.00	0.00	0.08	0.00	0.00	1.39	0.20
Existing Investment	Distribution Pipe	Food City Plaza STC - Area 80 - 1161	30053	Value Driven	-	-	(226)	(239)	14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.84	0.00	0.00	0.00	0.01	0.00	0.00	0.64	0.09
Existing Investment	Distribution Pipe	Second St - Area 50 - 1194	30093	Value Driven	-	-	(1,272)	(1,346)	74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.61	0.00	0.00	0.00	0.33	0.00	0.00	2.74	0.37
Existing Investment	Distribution Pipe	Yonge St - GTA East - Area 30 - 1358	30175	Value Driven	-	-	(1,761)	(1,879)	118	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	113.11	0.00	0.00	0.00	0.17	0.00	0.00	4.38	0.62
Emergent	Distribution Pipe	Oakwood St PTC - Area 80 - 2030	30068	Value Driven	-	-	(1,210)	(1,271)	61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.50	0.00	0.00	0.00	0.11	0.00	0.00	2.72	0.39
Existing Investment	Distribution Pipe	Ross St - Area 50 - 1210	30092	Value Driven	-	-	(1,105)	(1,161)	57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.95	0.00	0.00	0.00	0.59	0.00	0.00	1.98	0.28
Emergent	Distribution Pipe	Oak St 2 - Area 50 - 1655	30090	Value Driven	-	-	(635)	(671)	36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.12	0.00	0.00	0.00	0.07	0.00	0.00	1.42	0.21
Existing Investment	Distribution Pipe	Oak St 1 - Area 50 - 1654	30089	Value Driven	-	-	(870)	(905)	35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.08	0.00	0.00	0.00	0.05	0.00	0.00	1.48	0.21
Existing Investment	Distribution Pipe	Forkes Rd E PTC - Area 80 - 1132	30054	Value Driven	-	-	(1,223)	(1,249)	26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.33	0.00	0.00	0.00	0.43	0.00	0.00	0.22	0.04
Existing Investment	Distribution Pipe	VSM-HWY 7 Dufferin St Perth	734548	Value Driven	-	$ 3,735	(802)	(815)	13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.28	0.00	0.00	0.00	0.01	0.00	0.00	0.58	0.08
Existing Investment	Distribution Pipe	William St - Eastern - Area 60 - 1092	30393	Value Driven	-	-	(968)	(1,024)	56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.30	0.00	0.00	0.00	0.06	0.00	0.00	2.31	0.31
Existing Investment	Distribution Pipe	Woodside Dr - Eastern - Area 60 - 1178	30395	Value Driven	-	-	(1,163)	(1,218)	54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.05	0.00	0.00	0.00	0.22	0.00	0.00	1.85	0.26
Existing Investment	Distribution Pipe	Oak St - Eastern - Area 60 - 1133	30373	Value Driven	-	-	(999)	(1,047)	48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	45.52	0.00	0.00	0.00	0.08	0.00	0.00	2.09	0.30
Existing Investment	Distribution Pipe	TOR10YR - Parklawn - Hallmark to Lunness Replacement	503165	Value Driven	-	-	(910)	(910)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	A80: Shurie Rd LINC, VS Replacement	30076	Value Driven	-	-	(349)	(365)	17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.96	0.00	0.00	0.00	0.01	0.00	0.00	0.75	0.11
Existing Investment	Distribution Pipe	Lockhart St NOTL - Area 80 - 1189	30063	Value Driven	-	-	(441)	(456)	15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.93	0.00	0.00	0.00	0.01	0.00	0.00	0.61	0.09
Existing Investment	Distribution Pipe	TOR10YR - Scarden and Tourmaline Replacement - Network # 455	735822	Value Driven	-	-	(1,035)	(1,035)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Main St (MORATORIUM UNTIL 2025) - Area 50 - 1223	30087	Value Driven	-	-	(599)	(625)	26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.00	0.00	0.00	0.00	0.14	0.00	0.00	0.81	0.10
Existing Investment	Distribution Pipe	TOR10YR - Weston - St Lucie Replacement	733681	Value Driven	-	-	(1,296)	(1,296)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Bayview & Steeles CC Replacement	1693	Value Driven	-	-	154	(142)	295	0.00	0.00	0.00	0.00	0.00	0.00	0.00	123.51	0.00	0.00	0.00	33.27	0.00	0.00	0.00	0.00	0.00	4.22	123.51	10.76
Existing Investment	Distribution Pipe	TOR10YR - Birchmount North Ellesmere Replacement - Network # 455	735847	Value Driven	-	-	(942)	(942)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Lavinia St FE - Area 80 - 1171	30062	Value Driven	-	-	(1,158)	(1,183)	25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.74	0.00	0.00	0.00	0.04	0.00	0.00	1.35	0.19
Emergent	Distribution Pipe	Spruce Ave - GTA East - Area 30 - 1491	30171	Value Driven	-	-	(1,036)	(1,365)	330	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	314.63	0.00	0.00	0.00	0.49	0.00	0.00	12.59	1.80
Existing Investment	Distribution Pipe	TOR10YR - Aragon and Malamute Replacement - Network # 455	735821	Value Driven	-	-	(1,000)	(1,000)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	BOVAIRD & MISSISSAUGA DISTRICT	18893	Value Driven	-	$ 7,574	(118)	(180)	61	0.00	0.10	0.00	0.00	0.00	0.41	0.00	3.64	0.00	0.00	0.00	0.44	0.00	0.00	0.00	0.00	0.00	44.26	12.35	0.09
Emergent	Distribution Stations	HWY 9/SECOND LINE RD. DISTRICT	18895	Value Driven	-	$ 7,574	(66)	(100)	34	0.00	0.10	0.00	0.00	0.00	0.41	0.00	0.00	0.00	0.00	0.00	33.04	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.20
Emergent	Distribution Stations	KING ST E/OLD KING RD DISTRICT (BOLTON)	18906	Value Driven	-	$ 7,574	(42)	(100)	58	0.00	0.10	0.00	0.00	0.00	0.41	0.00	0.00	0.00	0.00	0.00	0.43	0.00	0.00	0.00	0.00	0.00	44.26	12.35	0.09
No Longer in Plan	Distribution Stations	BRAMALEA & ADVANCE BLVD. DISTRICT	18909	Value Driven	-	-	(97)	(97)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	20003A FARMERS LANE DISTRICT- N/W COR KING RD	735305	Value Driven	-	$ 7,574	(100)	(100)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	21102A - BRESLER & AIRPORT	101120	Mandatory	-	$ 454,462	(273)	(273)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	20702A DIXIE & BRITANNIA DISTRICT	735175	Mandatory	$ 129,797	$ 7,574	(187)	(187)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	20782B DERRY & TOMKEN IP DISTRICT	735174	Mandatory	-	$ 7,574	(191)	(191)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	33010A YONGE & GLEN CAMERON DISTRICT	735779	Value Driven	-	$ 291,613	(172)	(172)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	17536A FENMAR & STEELES DISTRICT	738908	Value Driven	$ 11,636	$ 284,947	(177)	(177)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	14378A - TRETHEWAY & GREENBROOK DISTRICT	101006	Value Driven	$ 285,813	-	(198)	(198)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	32311A - WILLIAM & PRESTON LAKE DISTRICT	101057	Value Driven	-	$ 7,726	(207)	(207)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	SPADINA & MACPHERSON DISTRICT	18886	Value Driven	-	$ 7,574	(459)	(832)	374	0.00	0.10	0.00	0.00	0.00	0.44	0.00	0.00	0.00	0.00	0.00	366.62	0.00	0.00	0.00	0.00	0.00	4.43	0.00	2.17
Emergent	Distribution Stations	3167839 ALTON TOWERS & MCCOWAN DISTRICT	735184	Mandatory	-	$ 2	0	(0)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	3167988 COMMANDER & MCCOWAN DISTRICT	735185	Value Driven	-	$ 2	0	(0)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	3226642 LATIMER & ROSELAWN DISTRICT STATION	735186	Value Driven	-	$ 10,604	(169)	(169)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	17904A Rathburn and Dorlen District	735176	Value Driven	-	$ 658,071	(388)	(388)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	GRASSYBROOK & MCKENNY DISTRICT	18850	Value Driven	-	-	(92)	(93)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Emergent	Distribution Stations	85151A - FORKS & TOWNLINE DISTRICT	101123	Mandatory	-	$ 7,574	(4)	(4)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	81210A - ROXBOROUGH & RIDGE DISTRICT LP	101122	Value Driven	-	$ 7,574	3,509	(187)	3,695	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	3,293.64	0.00	0.00	0.00	0.00	0.00	0.04	247.02	154.39
Emergent	Distribution Stations	A80: 1826 MILLER RD DISTRICT STATION	101115	Mandatory	$ 389,392	$ 318,123	(178)	(178)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	A80: EIGHTH AVE LOUTH & 5TH ST DISTRICT	101113	Value Driven	$ 3,245	$ 454,462	(250)	(250)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	61128A - CAMPBELL & MCNABB DISTRICT	101154	Value Driven	-	-	(140)	(141)	1	0.00	0.02	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.71	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.04
Existing Investment	Distribution Stations	6B435A - CORKSTOWN & WESTDALE DISTRICT	101153	Value Driven	-	$ 239,123	(30)	(135)	105	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	65.87	0.00	0.00	0.00	0.00	0.00	36.02	0.00	3.50
No Longer in Plan	Distribution Stations	6B562A - CAMPEAU & TERON DISTRICT HP (O.P.P.)	101152	Value Driven	-	-	88	(131)	219	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.04	0.00	0.00	0.00	0.00	0.00	185.27	0.00	0.20
No Longer in Plan	Distribution Stations	ONTARIO & DEERE DISTRICT LP	18851	Value Driven	-	-	3,254	(166)	3,420	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	3,048.36	0.00	0.00	0.00	0.00	0.00	0.04	228.63	142.89
Existing Investment	Distribution Stations	14887A GLAMORGAN & KENNEDY DISTRICT	735187	Value Driven	-	$ 10,604	(202)	(202)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	6B758A - EAGLESON & HAZELDEAN DISTRICT	101151	Value Driven	-	-	(53)	(131)	77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.04	0.00	0.00	0.00	0.00	0.00	44.26	0.00	0.20
Existing Investment	Distribution Stations	BAYVIEW & SHEPPARD DISTRICT	18812	Value Driven	-	$ 335,209	(128)	(198)	70	0.00	1.06	0.00	0.00	0.00	4.49	0.00	3.93	0.00	0.00	0.00	4.39	0.00	0.00	0.00	0.00	0.00	55.71	0.00	0.21
Existing Investment	Distribution Stations	2885749 Taunton and Gillett	735304	Value Driven	-	$ 454,462	(206)	(268)	62	0.00	0.10	0.00	0.00	0.00	0.41	0.00	0.00	0.00	0.00	0.00	39.14	0.00	0.00	0.00	0.00	0.00	20.02	0.00	2.49
Existing Investment	Distribution Stations	33171A - MAJOR MACKENZIE & VELLORE WOODS DISTRICT (VAUGHAN)	735170	Mandatory	-	$ 109,828	(65)	(65)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	30988A CONCESSION 2 & TWMARC DISTRICT	735172	Value Driven	$ 12,980	$ 289,000	(180)	(180)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	17461A CAVERLY & MARTINGROVE DISTRICT	735188	Value Driven	-	$ 10,604	(118)	(118)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	32564A - MILL RD & KING SIDEROAD DISTRICT	735173	Value Driven	-	$ 328,939	172	(194)	366	0.00	1.83	0.00	0.00	0.00	7.71	0.00	0.02	0.00	0.00	0.01	356.21	0.00	0.00	0.00	0.00	0.00	0.05	0.04	0.04
Existing Investment	Distribution Stations	33300A ISLINGTON & HWY # 407 HP DIST	735301	Value Driven	-	$ 7,574	227	(224)	451	0.00	0.97	0.00	0.00	0.00	4.09	0.00	0.00	0.00	0.00	0.00	3.40	0.00	0.00	0.00	0.00	0.00	442.58	0.00	0.00
Existing Investment	Distribution Stations	31335A GILBERT& YONGE DISTRIUCT (AURO	735300	Value Driven	-	$ 7,574	251	(132)	383	0.00	1.69	0.00	0.00	0.00	7.14	0.00	0.02	0.00	0.00	0.01	329.69	0.00	0.00	0.00	0.00	0.00	44.26	0.04	0.03
No Longer in Plan	Distribution Stations	LESLIE & STEELES DISTRICT	23730	Value Driven	-	-	(96)	(166)	70	0.00	1.45	0.00	0.00	0.00	6.11	0.00	0.00	0.00	0.00	0.00	62.02	0.00	0.00	0.00	0.00	0.00	0.43	0.00	0.36
No Longer in Plan	Distribution Stations	FINCH & HALESIA DISTRICT	20376	Value Driven	-	-	(200)	(201)	1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.00	0.00	0.00	0.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	44512A YANKEE LINE & RUSSELL DISTRICT	735168	Value Driven	-	$ 337,059	(199)	(199)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	14435A BIRMINGHAM & NINTH DISTRICT	735177	Value Driven	-	$ 359,509	(196)	(196)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	12696A BROOKFIELD AND DONINO DISTRICT	735179	Value Driven	$ 87,099	-	(241)	(241)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	3381554 MCCOWAN AND SHEPPARD DISTRICT	735311	Mandatory	-	$ 10,604	(152)	(152)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	BAYVIEW & BYNG DISTRICT	18815	Value Driven	-	$ 731,365	(348)	(400)	51	0.00	1.06	0.00	0.00	0.00	4.49	0.00	0.00	0.00	0.00	0.00	1.09	0.00	0.00	0.00	0.00	0.00	44.70	0.00	0.04
Existing Investment	Distribution Stations	12377A PURPLE DUSK TRAIL & NEILSON DISTRICT	735180	Value Driven	$ 148,877	-	(186)	(186)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	32717A - WESTON RD & KING RD DISTRICT	101058	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	35053A Dufferin Langstaff (langstaff & 407)	735303	Value Driven	-	$ 6,403	319	(132)	451	0.00	0.97	0.00	0.00	0.00	4.09	0.00	0.00	0.00	0.00	0.00	3.40	0.00	0.00	0.00	0.00	0.00	442.58	0.00	0.00
Existing Investment	Distribution Stations	3226575 SHEPPARD & MORNINGSIDE DISTRICT	735181	Value Driven	-	$ 279,091	(165)	(165)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	33525A Bathurst & Rutherford hp-ip	735302	Value Driven	-	$ 259,422	334	(153)	487	0.00	0.97	0.00	0.00	0.00	4.09	0.00	0.00	0.00	0.00	0.00	3.67	0.00	0.00	0.00	0.00	0.00	478.18	0.00	0.00
Emergent	Distribution Stations	A80: Lake and Louisa DIST STN - Aband and lay IP main	735163	Mandatory	-	$ 485,721	(291)	(291)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	81197A BOWEN & STEVENSVILLE DISTRICT	735299	Mandatory	-	$ 7,574	(4)	(4)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	BAY & SCOLLARD DISTRICT LP	18818	Value Driven	-	$ 10,604	(659)	(660)	1	0.00	0.09	0.00	0.00	0.00	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00
Existing Investment	Distribution Stations	DELORAINE & YONGE DISTRICT	18887	Value Driven	-	$ 10,604	(58)	(185)	127	0.00	1.67	0.00	0.00	0.00	7.05	0.00	0.00	0.00	0.00	0.00	66.96	0.00	0.00	0.00	0.00	0.00	49.13	0.00	2.20
Existing Investment	Distribution Stations	BRIMLEY & ELESMERE DISTRICT	18816	Value Driven	-	$ 10,604	(230)	(277)	47	0.00	0.18	0.00	0.00	0.00	0.76	0.00	0.00	0.00	0.00	0.00	1.09	0.00	0.00	0.00	0.00	0.00	44.70	0.00	0.04
Existing Investment	Distribution Stations	2936953 MEADOWVALE & GENERATION DISTRICT	735182	Value Driven	-	$ 279,091	(165)	(165)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	A80: Townline Rd, Welland, Station Replacement	18917	Value Driven	-	$ 7,574	(18)	(93)	75	0.00	1.79	0.00	0.00	0.00	7.56	0.00	0.00	0.00	0.00	0.00	61.16	0.00	0.00	0.00	0.00	0.00	0.78	0.00	3.42
No Longer in Plan	Distribution Stations	COUNTY RD #55 HWY #9 DISTRICT (NEW TECUSETH)	18911	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	HIGHWAY #3 & HOUSE RD DISTRICT	18916	Mandatory	-	$ 7,574	(123)	(166)	43	0.00	1.79	0.00	0.00	0.00	7.56	0.00	0.00	0.00	0.00	0.00	30.98	0.00	0.00	0.00	0.00	0.00	0.78	0.00	2.00
Existing Investment	Distribution Stations	2936745 MARKHAM & VERNE DISTRICT	735183	Value Driven	-	$ 10,604	(87)	(87)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	21116A - DERRY & HISTORIC TRAIL	101119	Mandatory	-	$ 454,462	(273)	(273)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	33534A STEELES & BAYVIEW DISTRICT	735169	Value Driven	-	-	10	0	10	0.00	1.83	0.00	0.00	0.00	7.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	ST. PAUL & SANDFIELD DISTRICT (ALEXANDRIA)	23766	Value Driven	-	-	(167)	(167)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Existing Investment	Distribution Stations	31428A - RAM FOREST & WESLEY CORNERS	101056	Value Driven	-	$ 7,574	(207)	(207)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HARVIE & MORRISON DISTRICT	18888	Value Driven	-	$ 14,391	(420)	(550)	130	0.00	1.67	0.00	0.00	0.00	7.05	0.00	0.00	0.00	0.00	0.00	66.96	0.00	0.00	0.00	0.00	0.00	49.13	0.00	5.50
Emergent	Distribution Stations	A60: Campbell & McNabb District (61128A)	738891	Value Driven	-	$ 221,703	(122)	(122)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	SHEPPARD AVE E & GRAND MARSHALL DISTRICT	18844	Value Driven	-	$ 200,728	(105)	(110)	4	0.00	0.13	0.00	0.00	0.00	0.55	0.00	0.00	0.00	0.00	0.00	1.75	0.00	0.00	0.00	0.00	0.00	1.89	0.00	0.05
No Longer in Plan	Distribution Stations	REPLIN & LAWRENCE DISTRICT	18845	Value Driven	-	-	(50)	(119)	70	0.00	0.84	0.00	0.00	0.00	3.56	0.00	0.00	0.00	0.00	0.00	61.27	0.00	0.00	0.00	0.00	0.00	0.63	0.00	3.27
Existing Investment	Distribution Stations	(O)-ELLESMERE / BUDEA	18962	Value Driven	-	$ 7,574	(123)	(126)	3	0.00	0.09	0.00	0.00	0.00	0.38	0.00	0.00	0.00	0.00	0.00	0.43	0.00	0.00	0.00	0.00	0.00	1.85	0.00	0.01

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
No Longer in Plan	Distribution Stations	YORKGATE & FINCH DISTRICT	18963	Value Driven	-	-	(180)	(261)	80	0.00	0.21	0.00	0.00	0.00	0.89	0.00	0.00	0.00	0.00	0.00	3.19	0.00	0.00	0.00	0.00	0.00	75.82	0.00	0.20
Existing Investment	Distribution Stations	CALEDONIA & RAITHERM DISTRICT	18964	Value Driven	-	$ 10,604	(318)	(325)	7	0.00	0.02	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	6.59	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.05
Emergent	Distribution Stations	2023 LP Station Mitigation Program	738918	Mandatory	$ 350,452	-	(261)	(261)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	MCCOWAN AND SHEPPARD DISTRICT	18965	Value Driven	-	-	(381)	(382)	1	0.00	0.01	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.56	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.05
Emergent	Distribution Stations	6A149A Kemptville District	738923	Mandatory	-	$ 239,123	(135)	(135)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	12902A - STUBBS & LESLIE DISTRICT	101050	Mandatory	-	$ 169,385	(93)	(93)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	61128A CAMPBELL & MCNABB DISTRICT	735166	Mandatory	-	$ 239,123	224	(141)	366	0.00	1.69	0.00	0.00	0.00	7.14	0.00	0.02	0.00	0.00	0.01	356.21	0.00	0.00	0.00	0.00	0.00	0.39	0.04	0.04
No Longer in Plan	Distribution Stations	6B602A STARTOP DISTRICT XHP	735165	Value Driven	-	-	208	(131)	339	0.00	1.69	0.00	0.00	0.00	7.14	0.00	0.02	0.00	0.00	0.01	329.69	0.00	0.00	0.00	0.00	0.00	0.36	0.04	0.03
Existing Investment	Distribution Stations	6B631A MCCARTHY DR AND HUNT CLUB RD	735164	Value Driven	-	$ 239,123	(135)	(135)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	Header Stations Rebuilds Area 30	739691	Value Driven	$ 366,483	-	(39)	(39)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	Meter and Instrument Exchanges	739670	Mandatory	$ 109,566	-	(43)	(43)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	Header Stations Rebuilds Area 10	739689	Mandatory	$ 505,746	-	(34)	(34)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	WATE: 20S-603 Elmira South. Stn FIMP	735257	Value Driven	-	-	(91)	(91)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	Header Station Rebuilds Area 60	739692	Mandatory	$ 244,322	-	(57)	(57)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	Sales Stations Rebuilds Area 60	739696	Value Driven	$ 244,322	-	(97)	(97)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	Sales Stations Rebuilds Area 10	739693	Mandatory	$ 361,596	-	(143)	(143)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	A80: Logan Ave, Welland, Station Replacement- aband LP -replace with	738017	Value Driven	$ 16,874	$ 924,072	(558)	(558)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	Sales Stations Rebuilds Area 20	739694	Mandatory	$ 224,072	-	(73)	(73)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	Header Stations Rebuilds Area 20	739690	Mandatory	$ 244,322	-	(97)	(97)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	LEG - ERX Cloudlink Modem Replacement	739580	Value Driven	$ 391,014	$ 1,369,065	(1,099)	(1,099)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	Harmer District Station	3455	Value Driven	-	-	(2,515)	(2,515)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	Sales Stations Rebuilds Area 30	739695	Mandatory	$ 244,322	-	(88)	(88)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	Finch Kennedy Birchmount Reinforcement	739488	Value Driven	$ 501,762	-	(373)	(373)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	Welland IP NW8925 Reinforcement	7727	Mandatory	-	-	(1,802)	(1,870)	68	0.00	(169.52)	237.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	Canada Wonderland Reinforcement	739075	Mandatory	$ 588,049	-	(437)	(437)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	NW 4521 Avondale Drive Reinforcement SRP	736667	Mandatory	-	-	(207)	(207)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	NW3834 Glenbourne Park Dr Reinforcement	738860	Mandatory	$ 154,189	-	(101)	(101)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	NW 3750 & 3832 Concession Rd 2 Reinforcement SRP	736664	Mandatory	-	-	(233)	(233)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	A80: NW 8521_8520 Brawn Rd - Wainfleet - Reinforcement SRP	736685	Mandatory	$ 11,737	$ 1,171,512	(826)	(826)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Real Estate & Workplace Services	Thorold Operations Centre - New Building	737754	Mandatory	$ 64,899	$ 832,363	8,611	(16,450)	25,061	0.00	0.00	0.00	0.00	17,370.60	331.36	0.00	0.00	6,257.82	1,101.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	Thorold Regional Office - Building & Site	8681	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	Oshawa Operations Depot Improvements	6101	Value Driven	-	-	159	(1,039)	1,198	0.00	0.00	0.00	0.00	1,197.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	VPC-Link and stairwells	3637	Value Driven	-	-	1,359	(1,196)	2,555	0.00	0.00	0.00	0.00	2,554.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Real Estate & Workplace Services	New GTA West Site	100548	Value Driven	$ -	$ -	3,780	0	3,780	0.00	0.00	0.00	0.00	3,669.68	15.39	0.00	0.00	0.00	94.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	Kelfield Operations Centre - Land Purchase	8701	Value Driven	-	-	2,008	(20,696)	22,704	0.00	0.00	0.00	0.00	22,703.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Real Estate & Workplace Services	GTA East - New Build - Peterborough	739714	Mandatory	$ 259,594	-	2,614	(8,471)	11,085	0.00	0.00	0.00	0.00	9,230.75	85.73	0.00	0.00	1,743.98	24.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Real Estate & Workplace Services	VPC Security Improvements	739533	Mandatory	$ 1,297,972	-	(966)	(966)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	VPC Core and Shell	8782	Value Driven	-	-	13,435	(14,849)	28,284	0.00	0.00	0.00	0.00	15,222.47	122.03	0.00	0.00	12,923.24	16.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	TIS Technology and Innovation Lab	22004	Value Driven	-	-	(414)	(414)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	Arnprior Operations Centre Obsolescence	8677	Value Driven	-	-	132	(1,206)	1,337	0.00	0.00	0.00	0.00	1,369.10	(4.46)	0.00	0.00	0.00	(27.44)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	MSB Demolition & New Administrative Parking	6087	Value Driven	-	-	2,807	(373)	3,179	0.00	0.00	0.00	0.00	2,902.52	38.72	0.00	0.00	0.00	237.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	OWP Replacement	102209	Value Driven	-	$ 256,112	1,673	(386)	2,059	0.00	0.00	0.00	2,058.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Technical Training Technology 2022	102198	Value Driven	$ -	$ -	1,268	0	1,268	0.00	0.00	0.00	0.00	466.33	0.00	0.00	0.00	801.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	QR Code for Infractions	734986	Value Driven	-	-	2,163	0	2,163	388.75	(181.41)	0.00	0.00	0.00	0.00	0.00	0.00	1,955.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Auto-Dispatching	734985	Value Driven	-	-	1,763	(295)	2,059	2,058.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Emergency Dispatch Capability Advancement	734984	Value Driven	-	-	6,738	0	6,738	6,479.10	0.00	0.00	0.00	259.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	Increase Efficiency with Innovation	734983	Value Driven	-	-	10,964	(6,981)	17,945	540.65	2,364.00	0.00	0.00	0.00	0.00	0.00	0.00	15,040.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Customer Account creation Automation through GetConnected	734982	Value Driven	-	-	3,445	0	3,445	1,943.73	0.00	0.00	0.00	647.91	0.00	0.00	0.00	853.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Work Management Ops Support Program	734981	Value Driven	-	-	161	(2,125)	2,286	1,428.70	0.00	0.00	0.00	857.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	EG - Customer Data Analytics Solutions (2022)	102256	Value Driven	$ -	$ -	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	Deferral Acct Harmonization + Unaccounted for Gas + Cost Allocation 2(	737263	Value Driven	$ 265,110	-	16	0	16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	General Service Rebasing Changes	736081	Value Driven	-	$ 15,366,694	(7,052)	(12,384)	5,333	0.00	0.00	0.00	0.00	5,332.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	EG - Building Management Systems Solution (2025)	102245	Value Driven	-	-	215	(230)	445	0.00	0.00	0.00	0.00	444.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	HVAC Portal & Get Connected Integration	734920	Value Driven	-	-	635	0	635	388.75	0.00	0.00	0.00	103.67	0.00	0.00	0.00	142.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Fiber Technology - Damage Reduction Technology Support	734915	Value Driven	$ 908,581	-	2,040	0	2,040	0.00	1,274.82	0.00	0.00	764.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	Records Management Upgrade 2023	735002	Value Driven	-	$ 480,209	3,974	(469)	4,443	0.00	476.09	0.00	1,983.69	1,983.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Cost & Schedule Management (Ecosys)	735733	Value Driven	-	$ 1,920,837	2,435	(1,507)	3,942	0.00	0.00	0.00	1,964.17	0.00	0.00	0.00	0.00	1,977.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	Customer Care Strategy 2024	740111	Value Driven	-	$ 960,418	771	(671)	1,442	0.00	0.00	0.00	0.00	1,441.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Inventory Management	734919	Value Driven	-	-	7,340	0	7,340	0.00	0.00	0.00	3,115.22	0.00	0.00	0.00	0.00	4,224.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	RPA's for Customer Care 2024	740113	Value Driven	-	$ 480,209	4,150	(335)	4,485	0.00	0.00	0.00	4,484.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	EG - DataStage Analytics (2025)	102112	Value Driven	-	-	326	(662)	988	0.00	0.00	0.00	0.00	988.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Reporting & Analytics	734602	Value Driven	-	-	2,858	(3,000)	5,858	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5,857.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Customer Inquiry Tool Automation	734910	Value Driven	-	-	200	(414)	614	0.00	0.00	0.00	0.00	239.97	0.00	0.00	0.00	374.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Expansion Surcharge Capability Advancement	734911	Value Driven	-	-	197	(192)	388	0.00	0.00	0.00	0.00	111.10	0.00	0.00	0.00	277.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Attachment Growth Program	734912	Value Driven	-	-	(697)	(2,125)	1,429	0.00	0.00	0.00	0.00	1,428.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Fleet Asset Management Program	734914	Value Driven	-	-	(252)	(633)	381	0.00	0.00	0.00	0.00	380.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	2022 - CIS Migration from SAP HEC to Enbridge Cloud @ Azure	102829	Value Driven	$ -	$ -	6,941	0	6,941	0.00	6,940.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	Performance Optimization & Quality Assurance	740274	Value Driven	-	$ 480,209	5,142	(748)	5,891	0.00	0.00	0.00	0.00	5,558.02	0.00	0.00	0.00	332.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Engineering & STO Win10 lifecycle 2022	102324	Value Driven	$ -	$ -	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Fleet Alignment Solution	734913	Value Driven	-	-	964	0	964	0.00	0.00	0.00	0.00	279.90	0.00	0.00	0.00	684.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	WRFT for Station Techs	739860	Value Driven	-	$ 576,251	5,336	(402)	5,738	844.52	844.52	0.00	844.52	844.52	0.00	0.00	0.00	2,359.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	5 week Planning Tool	739859	Value Driven	-	$ 5,122,231	21,370	(4,404)	25,775	12,887.27	12,887.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Construction Program	735071	Value Driven	-	-	(697)	(2,125)	1,429	1,428.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Push to Talk Radios - 2023	101827	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Payment Enhancements 2022	102297	Value Driven	$ -	$ -	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Contract Market Harmonization	102291	Value Driven	$ 2,725,742	$ 6,402,789	(3,643)	(12,753)	9,110	0.00	0.00	0.00	0.00	9,109.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	FRA Rollout to LUG	734918	Value Driven	-	-	1,946	(993)	2,940	0.00	0.00	0.00	0.00	1,019.86	0.00	0.00	0.00	1,056.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	863.69	0.00
Emergent	TIS	MMR Enhancements 2024	740105	Value Driven	-	$ 720,314	218	(503)	721	0.00	0.00	0.00	0.00	720.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Locate Delivery Enhancements	734917	Value Driven	$ 324,493	-	(833)	(1,728)	895	0.00	0.00	0.00	0.00	839.69	0.00	0.00	0.00	54.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.61	0.00
Existing Investment	TIS	Locate Technology Advancements	734916	Value Driven	$ 194,696	-	138	(145)	283	0.00	(118.96)	0.00	0.00	223.92	0.00	0.00	0.00	131.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.87	0.00
Existing Investment	TIS	EG - Customer Data Analytics Solutions (2023)	102342	Value Driven	$ 296,923	-	436	0	436	0.00	0.00	0.00	0.00	436.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	EG - Customer Data Analytics Solutions (2024)	102343	Value Driven	-	-	258	0	258	0.00	0.00	0.00	0.00	257.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	EG - Customer Data Analytics Solutions (2025)	102345	Value Driven	-	-	182	(298)	480	0.00	0.00	0.00	0.00	480.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Material Traceability	102359	Value Driven	-	-	(19)	(4,783)	4,764	0.00	0.00	0.00	0.00	4,763.81	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	Digital Ambition - IMS Compliance & Analytics 2024	740045	Value Driven	-	$ 512,223	(14)	(179)	164	0.00	0.00	0.00	0.00	164.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	PressureViewer Integration	740057	Value Driven	-	$ 576,251	69	(402)	471	0.00	0.00	0.00	0.00	116.62	0.00	0.00	0.00	354.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	CIS - Measurement Canada Pressure Multiplier Enhancement	740077	Value Driven	$ 389,392	-	5,719	(288)	6,007	0.00	0.00	6,007.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Corrosion Protection and Leak Survey Enhancement	734819	Value Driven	-	-	5,635	(1,594)	7,230	0.00	0.00	0.00	0.00	7,199.01	0.00	0.00	0.00	29.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.37	0.00
No Longer in Plan	TIS	Scheduling and Dispatching Automation - FieldRep Skillset	734817	Value Driven	-	-	2,363	0	2,363	0.00	1,223.85	0.00	0.00	0.00	0.00	0.00	0.00	1,138.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	WRFT Enhancements 2023	734816	Value Driven	$ 530,220	-	3,900	(483)	4,383	0.00	2,270.22	0.00	0.00	0.00	0.00	0.00	0.00	2,112.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Customer Residential Pre-payment System	734815	Value Driven	-	-	3,423	0	3,423	1,943.73	283.40	0.00	0.00	207.33	0.00	0.00	0.00	988.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Online Customer Appointment Booking	734813	Value Driven	-	-	3,671	0	3,671	2,682.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	988.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	2024 ePackages	740228	Value Driven	-	$ 512,223	(22,775)	(356)	(22,419)	0.00	(22,418.84)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	Leak And Corrosion System Enhancements	740112	Value Driven	-	$ 832,363	8,534	(581)	9,115	0.00	518.33	0.00	0.00	0.00	0.00	0.00	40.89	780.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7,774.93	0.00
Existing Investment	TIS	Records Management Technology Obsolescence (2024-2026)	102364	Value Driven	-	$ 960,418	(9,106)	(16,768)	7,662	0.00	6,604.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,057.97	0.00
No Longer in Plan	TIS	Material Barcoding Expansion	736464	Value Driven	-	-	5,517	0	5,517	0.00	0.00	0.00	2,401.32	2,401.32	0.00	0.00	0.00	714.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	Hydrogen Blending And RNG Initiatives	739003	Value Driven	$ 324,493	$ 448,195	(511)	(554)	43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.84	0.00
Emergent	TIS	Conflict Locate Portal	740492	Value Driven	-	$ 720,314	1,015	(503)	1,518	0.00	0.00	0.00	0.00	727.73	0.00	0.00	0.00	788.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.71	0.00
Emergent	TIS	Energy Transition Program - Energy Services 2023	736933	Value Driven	$ 106,044	-	1,523	(97)	1,620	0.00	0.00	0.00	0.00	1,619.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
Emergent	TIS	Energy Transition Program - Energy Services 2024	736934	Value Driven	-	$ 1,280,558	606	(894)	1,500	0.00	0.00	0.00	0.00	1,499.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Push to Talk Radios (2029)	101951	Value Driven	-	-	(913)	(913)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	Coating Remediation - Sandwich Comp Stn	740870	Mandatory	-	$ 559,343	(396)	(396)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	High Performance Coating 2023 - Dawn Plant E	737239	Mandatory	-	-	(98)	(98)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	High Performance Coating 2023 - Parkway	737238	Mandatory	-	-	(142)	(142)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	156 Generator Installation	739960	Mandatory	-	$ 91,567	312	(65)	377	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	355.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.13
Emergent	Compression Stations	Coating Remediation - Dawn N/S Header Valves	740866	Mandatory	-	$ 26,385	(19)	(19)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	Owen Sound Take-off (17T-502V)	740898	Compliance	$ 290,054	-	(258)	(258)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	STO Security Remediations (East)	740221	Mandatory	-	-	(414)	(414)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	Hagar 412FKR357 Major Overhaul and Foundation Work	740281	Value Driven	-	$ 7,577,971	294,938	(5,364)	300,302	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20,424.39	0.00	0.00	0.00	0.00	0.00	274,452.45	0.00	5,425.23
Emergent	Compression Stations	167 Turbo Rebuild	739561	Mandatory	$ 83,130	-	(45)	(45)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	Lobo B - Hydraulic Fuel Valve Replacement	740371	Value Driven	-	$ 631,498	(757)	(757)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Compression Stations	Siemens Valve Controllers Replacement - Parkway D	48223	Value Driven	-	$ 326,357	1,556	(296)	1,853	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,852.67	0.00	0.00
Emergent	Compression Stations	Dawn Dehy - Cabling Upgrade	740583	Value Driven	$ 19,337	-	(14)	(14)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Compression Stations	Siemens Valve Controllers Replacement - Lobo D	101576	Value Driven	-	$ 326,357	1,561	(292)	1,853	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,852.67	0.00	0.00
Emergent	Compression Stations	Dawn Foxboro DCS Workstations - Back up MCR	739547	Compliance	$ 180,478	-	(135)	(135)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	156 PLC Installation	740183	Value Driven	$ 19,337	-	202	(14)	216	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	216.26	0.00	0.00
Existing Investment	Compression Stations	Dawn E Siemens MCC replacement	48275	Value Driven	-	-	238	(333)	572	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	571.57	0.00	0.00
Emergent	Compression Stations	Parkway 602 Disch Valve - Replace	740935	Value Driven	-	$ 1,862,918	(1,341)	(1,341)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	Sandwich OBV-001 Valve and Actuator Replacement	740262	Value Driven	-	$ 527,932	(374)	(374)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	Methane Remediation Valve Replacement - Sandwich	740054	Value Driven	$ 28,196	-	1,013	(25)	1,038	0.00	0.00	0.00	0.00	1,038.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	Methane Remediation Valve Replacement - Remotes	740051	Value Driven	$ 47,579	-	996	(42)	1,038	0.00	0.00	0.00	0.00	1,038.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	Methane Remediation Valve Replacement - Dawn	740049	Value Driven	$ 68,460	-	977	(61)	1,038	0.00	0.00	0.00	0.00	1,038.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	Bright B Blowdown Valve Replacement	739994	Compliance	$ 86,372	-	974	(65)	1,038	0.00	0.00	0.00	0.00	1,038.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Compression Stations	Plant J SOLAR HMI Replacement	739988	Value Driven	$ 29,833	-	(22)	(22)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	HAMI: Steel Riser Replacement Proposal	735537	Value Driven	-	-	(625)	(625)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	CNG Station Project - #5	503412	Mandatory	-	$ 1,306,551	(1,317)	(1,317)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	TBAY: 399A to EZR Conversion Kit	740529	Mandatory	$ 22,303	-	(16)	(16)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	Bellville Yard Station	503415	Value Driven	-	-	(1,341)	(1,341)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	CNG Stations - Project #4	48667	Value Driven	-	$ 630,508	(377)	(377)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WIND - 06D-401 Belle River Gate - Replace heater	101608	Value Driven	-	-	(232)	(232)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	WIND - 06B-401 Grand Marais - reg repl & liquid tank	502700	Value Driven	-	-	147	(186)	333	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	332.66	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00
Existing Investment	Distribution Stations	HAMI: Hamilton Gate 2, Noise Issues	735023	Value Driven	-	-	(738)	(738)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	KING: 22-24-704 College and Sidney DRS (27801009) Rebuild	101198	Value Driven	-	$ 1,404,450	(393)	(911)	518	0.00	16.92	0.00	0.00	0.00	71.36	0.00	0.00	0.00	0.00	0.00	65.87	0.00	0.00	0.00	0.00	0.00	360.24	0.00	3.50
No Longer in Plan	Distribution Stations	HAMI: 16Y-101 Woodward bio Gas, Hamilton, Reinforcement	735037	Value Driven	-	-	(331)	(331)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Existing Investment	Distribution Stations	19O-101 Dublin Gate	100993	Value Driven	-	-	(709)	(718)	9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.12	0.00	0.00	0.00	5.65	0.00	0.00	0.00	0.00	0.00	0.31	0.00	0.18
No Longer in Plan	Distribution Stations	LOND: 13O-206R London Baseline Reg Station	734688	Value Driven	-	-	(760)	(852)	92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	87.53	4.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI: 16X-601 Hamilton Gate 3, Hamilton, Full Station Rebuild and Hea	101086	Value Driven	-	-	(3,007)	(5,592)	2,585	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	2,191.01	335.32	0.00	0.00	0.00	0.00	0.00	17.15	0.00	41.53
Existing Investment	Distribution Stations	HAM-Lynden Gate Stn	101085	Value Driven	-	-	2,038	(355)	2,392	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	2,027.77	310.34	0.00	0.00	0.00	0.00	0.00	15.87	0.00	38.44
Existing Investment	Distribution Stations	KING - Under rated valve Trenton TBS 27601001	100777	Value Driven	-	-	(189)	(189)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	LOND - 12F-501 Payne Kimball Rebuild	735540	Value Driven	-	-	(7,290)	(7,320)	31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.48	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00
Existing Investment	Distribution Stations	SARN: 13F-501 Sarnia Industrial	734670	Value Driven	-	-	(6,786)	(6,830)	44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.09	0.00	0.00	0.00	3.10	0.00	0.00	0.00	0.00	0.00	37.91	0.00	0.00
Existing Investment	Distribution Stations	SARN: 12F-205 Novacor Moore Trans	734683	Value Driven	-	-	(2,081)	(2,089)	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	6.10	0.00	0.00	0.00	0.00	0.00	1.71	0.00	0.36
Existing Investment	Distribution Stations	SARN: 13F-503 Churchill Rd. Trans Stn	734697	Value Driven	-	-	(3,947)	(3,955)	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	6.10	0.00	0.00	0.00	0.00	0.00	1.71	0.00	0.36
Existing Investment	Distribution Stations	CHAT: 06J-103 Blenheim North Gate	734661	Value Driven	-	-	(167)	(168)	1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.34	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.00
Emergent	Distribution Stations	King: Esco SMS	734761	Value Driven	-	-	(556)	(555)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	CHAT - 09G-501 Tupperville Trans - heater replacement	502778	Value Driven	-	-	(601)	(600)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	KING: Ingredion (Casco SMS28801004) Rebuild	49888	Value Driven	-	-	(683)	(683)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WIND - 05A-203 LaSalle Boismier Ave - Heater replacement	101626	Value Driven	-	-	(1,963)	(1,980)	17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.41	3.62	0.00	0.00	0.00	0.00	0.00	1.85	0.00	0.38
Existing Investment	Distribution Stations	LOND: 14R-104 Beachville Domtar Trans Stn	734689	Value Driven	$ 644,564	$ 5,051,981	(8,161)	(8,976)	815	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	95.86	718.83	0.00	0.00	0.00	0.00	0.00	0.39	0.00	0.11
Emergent	Distribution Stations	King: Augusta CMS Rebuild	734775	Value Driven	-	-	(1,385)	(1,385)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	CHAT - 07J-301 Ridgetown North Transmission - Replace heater	101610	Value Driven	-	-	11	(337)	348	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.16	332.66	0.00	0.00	0.00	0.00	0.00	3.60	0.00	2.31
Existing Investment	Distribution Stations	CHAT - 07H-601 Burke Line - Heater Replacement	101354	Value Driven	-	-	733	0	733	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	266.09	456.90	0.00	0.00	0.00	0.00	0.00	5.32	0.00	4.41
Existing Investment	Distribution Stations	15O-401R Bryanston Gate	100994	Value Driven	-	-	(129)	(130)	0	0.00	0.02	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00
Existing Investment	Distribution Stations	KING: 29501001 Cornwall East Town Border rebuild	101199	Value Driven	-	-	(985)	(988)	3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.66	0.00	0.00	0.00	0.00	0.00	0.14	0.00	0.00
Existing Investment	Distribution Stations	WIND - 05A-601 Front & Malden full rebuild	502699	Value Driven	-	-	(1,048)	(1,085)	37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.23	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.10
Existing Investment	Distribution Stations	CHAT - 07G-601 Chatham North Gate	503334	Value Driven	-	-	(1,654)	(1,654)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	CHAT: 07K-409 MCKINLAY RD STATION	734671	Value Driven	-	-	(595)	(595)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	CHAT: 07H-501 MAYNARD LINE	734669	Value Driven	-	-	(278)	(278)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WIND: 06C-602 Puce Transmission	734665	Value Driven	-	-	(110)	(113)	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	3.10	0.00	0.00	0.00	0.00	0.00	0.31	0.00	0.33
Existing Investment	Distribution Stations	WIND: 06B-404 Bruce Ave	734667	Value Driven	-	-	(720)	(720)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	CHAT: 09F-501 Wallaceburg Baseline	734660	Value Driven	-	-	(957)	(1,291)	335	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	332.66	0.00	0.00	0.00	0.00	0.00	1.85	0.00	0.00
Existing Investment	Distribution Stations	LOND: 15Q-603 Canada Cement Trans Stn	734695	Value Driven	-	-	(2,397)	(2,403)	6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	5.64	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.33
Emergent	Distribution Stations	King: Williamsburg (2-91-02-001)TBS Heater & Filter Install	734759	Value Driven	-	-	266	(64)	330	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.00	329.40	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.03
Existing Investment	Distribution Stations	WIND: 06B-502 WALKER RD	734673	Value Driven	-	-	(246)	(246)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WIND - 06C-401 Manning Rd station rebuild	503331	Value Driven	-	-	(405)	(443)	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.24	32.97	0.00	0.00	0.00	0.00	0.00	0.62	0.00	0.20
Existing Investment	Distribution Stations	WIND - 06C-502 Patillo Rd station rebuild	503333	Value Driven	-	-	(835)	(873)	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.24	32.97	0.00	0.00	0.00	0.00	0.00	0.62	0.00	0.20
Existing Investment	Distribution Stations	BRAN: 12S-202 Fernlea Farm Distribution Station, CWT install/glycol line	100610	Value Driven	-	$ 147,915	(709)	(709)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	King: Strathcona TBS 2-81-02-001 Rebuild	734758	Value Driven	-	-	(771)	(774)	3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.10	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.17
No Longer in Plan	Growth	SRP_Southwest_Windsor_05A-201STN_Rebuild	101359	Value Driven	$ 244,934	$ 2,604,524	(1,740)	(1,742)	2	0.00	0.18	0.00	0.00	0.00	0.78	0.00	0.00	0.00	0.00	0.00	0.82	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.02
Existing Investment	Distribution Stations	LOND: 19O-601 Mitchell Gate	734687	Value Driven	-	-	(242)	(242)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WATE: 19U-201 Guelph West Gate Stn. FIMP	735226	Value Driven	-	-	(188)	(192)	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	3.35	0.00	0.00	0.00	0.00	0.00	0.33	0.00	0.36
No Longer in Plan	Distribution Stations	KING: Belleville Sidney St TBS (27801001) Valve Upgrades	100835	Mandatory	-	-	(109)	(174)	64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.31	0.00	0.00	0.00	3.70	0.00	0.00	0.00	0.00	0.00	52.90	0.00	7.49
Existing Investment	Distribution Stations	LOND - 17K-601R Grand Bend Northgate	100978	Value Driven	$ 1,318,186	-	(509)	(987)	478	0.00	1.97	0.00	0.00	0.00	8.33	0.00	0.00	0.00	0.00	0.00	422.91	0.00	0.00	0.00	0.00	0.00	21.63	0.00	23.06
Existing Investment	Distribution Stations	LOND: 16O-301 St. Mary's Gate	735275	Value Driven	-	-	(304)	(304)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	King: 22-23-799 Gananoque TBS Odourant Sweep Tank Repairs	739972	Mandatory	$ 115,029	-	(86)	(86)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	LOND: 15J-401 Forest Gate Transmission Station	735276	Value Driven	-	-	(138)	(138)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NBAY: Muskoka Falls TBS, Boiler Replacement	733757	Value Driven	-	-	(127)	(136)	10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	3.35	0.00	0.00	0.00	0.00	0.00	5.72	0.00	0.36
No Longer in Plan	Distribution Stations	NBAY: Ski Club/Trout Lake TBS, Boiler Replacement	733758	Value Driven	-	-	(165)	(209)	45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	3.35	0.00	0.00	0.00	0.00	0.00	40.96	0.00	0.36
No Longer in Plan	Distribution Stations	HAMI - Clappison's Corners	101135	Value Driven	-	-	137	(414)	551	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	362.30	0.00	0.00	0.00	0.00	0.00	185.27	0.00	3.50
No Longer in Plan	Distribution Stations	SUD: Lasalle TBS, Boiler Replacement	733753	Value Driven	-	-	(169)	(217)	48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	3.62	0.00	0.00	0.00	0.00	0.00	44.26	0.00	0.38
No Longer in Plan	Distribution Stations	SUD: Barrydowne, Boiler Replacement	733762	Value Driven	-	-	(93)	(138)	45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	3.35	0.00	0.00	0.00	0.00	0.00	40.96	0.00	0.36
No Longer in Plan	Distribution Stations	SUD: Frood TBS, Boiler Replacement	733754	Value Driven	-	-	389	(291)	680	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	3.35	0.00	0.00	0.00	0.00	0.00	676.35	0.00	0.36
No Longer in Plan	Distribution Stations	SUD: Inco Smelter SMS, Boiler Replacement	733755	Value Driven	-	-	(454)	(460)	6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	3.62	0.00	0.00	0.00	0.00	0.00	1.85	0.00	0.38
No Longer in Plan	Distribution Stations	SSM: Goulais Ave TBS Algoma 4, Boiler Replacement	733756	Value Driven	-	-	(611)	(621)	10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	3.62	0.00	0.00	0.00	0.00	0.00	6.18	0.00	0.38
Existing Investment	Distribution Stations	HAMI: Saint Gobain Abrasives, maintenance	735065	Value Driven	-	-	(122)	(122)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WATE: 21S-601 Fergus 1st Trans Stn FIMP, Heater Replacement, Obsole	735235	Value Driven	-	-	(698)	(698)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	HAMI: Hamilton Takeoff & Carlisle Gate, Rebuild	735038	Value Driven	-	-	(4,020)	(4,967)	947	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	329.47	0.00	0.00	0.00	0.00	0.00	617.56	0.00	0.20
Existing Investment	Distribution Stations	HAMI: SE Corner of HWY 5 & 6, Maintenance	735041	Value Driven	-	-	83	(230)	313	0.00	1.45	0.00	0.00	0.00	6.11	0.00	0.05	0.00	0.00	0.01	305.14	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.03
Existing Investment	Distribution Stations	HAMI: WATERDOWN NORTH DISTR'N STN, Boiler	735044	Value Driven	-	-	(767)	(767)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI: KIRKWALL/DOMINION, Full Rebuild	735045	Value Driven	-	-	(4,554)	(4,599)	45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	3.35	0.00	0.00	0.00	0.00	0.00	40.96	0.00	0.36
Existing Investment	Distribution Stations	HAMI: VOORTMAN STN, heater Replacement	735047	Value Driven	-	-	(347)	(383)	36	0.00	0.08	0.00	0.00	0.00	0.35	0.00	0.00	0.00	0.00	0.00	33.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.13
No Longer in Plan	Distribution Stations	HAMI :CALEDONIA TRANSMISSION STN, Rebuild	735048	Value Driven	-	-	(3,893)	(4,258)	365	0.00	8.07	0.00	0.00	0.00	34.04	0.00	0.01	0.00	0.00	0.01	284.95	0.00	0.00	0.00	0.00	0.00	37.91	0.03	0.03
No Longer in Plan	Distribution Stations	HAMI: Empire Steel, Maintenance	735050	Mandatory	-	-	(71)	(71)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	HAMI: Voith Fabrics, Maintenance	735051	Mandatory	-	-	(71)	(71)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI: Mye Canada, Maintenance	735056	Mandatory	-	-	(30)	(30)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	HAMI: 16Y-201R Cascade & Lanark, Hamilton, Vault Station Rebuild	101084	Value Driven	-	-	173	(414)	587	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.06	0.00	0.00	0.00	362.40	0.00	0.00	0.00	0.00	0.00	185.27	0.00	3.50
No Longer in Plan	Distribution Stations	WATE: 19S-201 Heidelburg Gate FIMP	735239	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HALT: Milton Hydro Dist Inc, Rebuild	735067	Value Driven	-	-	(122)	(122)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
No Longer in Plan	Distribution Stations	WATE: 23R-602 Rothsay Trans Stn,FIMP	735247	Value Driven	-	-	(124)	(124)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	WATE: 18S-401 Markdale Stn. FIMP	735248	Value Driven	-	-	(120)	(124)	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	3.62	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.38
Emergent	Distribution Stations	HALT: Georgetown TBS Rebuild, 21X-401R	739155	Value Driven	$ 128,913	-	(1,659)	(1,659)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	BRAN: 14S-601 Norwich Brick Gate Stn. FIMP	735249	Value Driven	-	-	(115)	(115)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HALT: Burlington Gate, boiler	735054	Value Driven	-	-	(1,314)	(1,314)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HALT: Morgan Thermal Ceramics, Maintenance	735055	Mandatory	-	-	(33)	(33)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	HALT-Winston Churchill & 10 Side Rd	101081	Value Driven	-	-	(44)	(414)	370	0.00	0.20	0.00	0.00	0.00	0.83	0.00	0.00	0.00	0.00	0.00	330.39	0.00	0.00	0.00	0.00	0.00	3.60	0.00	34.99
Existing Investment	Distribution Stations	HALT: Ford and Royal Windsor, Maintenance	735039	Value Driven	-	-	32	(307)	338	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	304.93	0.00	0.00	0.00	0.00	0.00	33.34	0.00	0.18
No Longer in Plan	Distribution Stations	HALT-Third Line and QEW Vault Station	101088	Value Driven	-	-	137	(414)	551	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	362.30	0.00	0.00	0.00	0.00	0.00	185.27	0.00	3.50
No Longer in Plan	Distribution Stations	HALT-Milton TBS	101089	Value Driven	-	-	(487)	(828)	341	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.01	332.66	0.00	0.00	0.00	0.00	0.00	6.18	0.00	1.99
No Longer in Plan	Distribution Stations	HALT - York and Broadway	101096	Value Driven	-	-	(374)	(414)	40	0.00	0.09	0.00	0.00	0.00	0.38	0.00	0.00	0.00	0.00	0.00	36.23	0.00	0.00	0.00	0.00	0.00	0.62	0.00	2.31
No Longer in Plan	Distribution Stations	HALT: EC Drury School,Rebuild	735049	Mandatory	-	-	(35)	(35)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HALT - Dundas and Meadowridge	101099	Value Driven	-	-	4	(307)	310	0.00	0.14	0.00	0.00	0.00	0.61	0.00	0.02	0.00	0.00	0.01	307.88	0.00	0.00	0.00	0.00	0.00	1.71	0.03	0.03
No Longer in Plan	Distribution Stations	HALT - Centennial and Guelph Line Vault Station	101125	Value Driven	-	-	137	(414)	551	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	362.30	0.00	0.00	0.00	0.00	0.00	185.27	0.00	3.50
No Longer in Plan	Distribution Stations	HALT: Saputo, rebuild	735052	Value Driven	-	-	148	(142)	290	0.00	1.34	0.00	0.00	0.00	5.66	0.00	0.04	0.00	0.00	0.01	282.41	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.03
Existing Investment	Distribution Stations	Halt: Ninth/Britannia, Rebuild	735035	Value Driven	-	$ 747,048	(423)	(447)	24	0.00	1.69	0.00	0.00	0.00	7.14	0.00	0.00	0.00	0.00	0.00	3.57	0.00	0.00	0.00	0.00	0.00	6.67	0.00	4.85
Existing Investment	Distribution Stations	LOND: 11O-306R Wellington and Fifth Reg Stn	734694	Value Driven	-	-	214	(128)	342	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	304.84	0.00	0.00	0.00	0.00	0.00	0.00	22.86	14.29
No Longer in Plan	Distribution Stations	WIND: 07H-402R Peter St Station LP	735375	Value Driven	-	-	3,491	(205)	3,695	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	3,293.64	0.00	0.00	0.00	0.00	0.00	0.04	247.02	154.39
Existing Investment	Distribution Stations	WATE: 17T-201 New Dundee Gate Stn FIMP	735250	Value Driven	-	-	(115)	(115)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	LOND: 13O-123R Napier and Blackfriars Reg Stn	734692	Value Driven	-	-	231	(138)	370	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	329.36	0.00	0.00	0.00	0.00	0.00	0.04	24.70	15.44
No Longer in Plan	Distribution Stations	LOND: 15R-608R Walter and Fyfe Reg Stn	734691	Value Driven	-	-	231	(138)	370	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	329.36	0.00	0.00	0.00	0.00	0.00	0.04	24.70	15.44
No Longer in Plan	Distribution Stations	LOND: 17M-601 Centralia Stn	734690	Value Driven	-	-	121	(216)	337	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.41	332.66	0.00	0.00	0.00	0.00	0.00	3.60	0.00	0.02
No Longer in Plan	Distribution Stations	LOND: 13O-212R Highbury and Brydges	734678	Value Driven	-	-	3,530	(166)	3,695	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	3,293.64	0.00	0.00	0.00	0.00	0.00	0.04	247.02	154.39
Existing Investment	Distribution Stations	WIND - 04B-401R Howard and Pike - Rebuild with Heater	101360	Value Driven	-	-	(121)	(179)	58	0.00	0.01	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.40	0.00	0.00	0.00	0.00	0.00	57.16	0.00	0.00
No Longer in Plan	Distribution Stations	WIND - 06B-548I Chrysler Paint - Heater Replacement	101357	Mandatory	-	-	(146)	(146)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	LOND: 13O-210R Hale and Burslem	734668	Value Driven	-	-	3,530	(166)	3,695	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	3,293.64	0.00	0.00	0.00	0.00	0.00	0.04	247.02	154.39
No Longer in Plan	Distribution Stations	WIND - 05B-401R Smith Ind Park - Station Rebuild with Heater	101347	Value Driven	-	-	(1,034)	(1,036)	1	0.00	0.02	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.76	0.00	0.00	0.00	0.00	0.00	0.46	0.00	0.02
No Longer in Plan	Distribution Stations	WIND - 03B-102R County Rd 20 & Concession Rd 3 - Heater addition	101342	Value Driven	-	-	(157)	(158)	1	0.00	0.02	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.76	0.00	0.00	0.00	0.00	0.00	0.42	0.00	0.00
No Longer in Plan	Distribution Stations	WIND - 04A-302R Texas Rd	502777	Value Driven	-	-	56	(274)	330	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	329.69	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00
No Longer in Plan	Distribution Stations	WIND - 03E-104C Thiessen Flower Shop - rebuild	502774	Value Driven	-	-	(163)	(168)	4	0.00	0.17	0.00	0.00	0.00	0.71	0.00	0.00	0.00	0.00	0.01	3.10	0.00	0.00	0.00	0.00	0.00	0.31	0.00	0.08
No Longer in Plan	Distribution Stations	WIND - 06B-517R Ypres LP - rebuild	502773	Value Driven	-	-	3,491	(205)	3,695	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3,293.64	0.00	0.00	0.00	0.00	0.00	0.36	247.02	154.39
No Longer in Plan	Distribution Stations	WIND - 06B-314R Isabelle Place LP - rebuild	502772	Value Driven	-	-	165	(204)	370	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	329.36	0.00	0.00	0.00	0.00	0.00	0.04	24.70	15.44
No Longer in Plan	Distribution Stations	WIND - 04D-601R Albuna Station rebuild	502701	Value Driven	-	-	(587)	(587)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	LOND: 10M-503R Main and Shackleton	734664	Value Driven	-	-	3,521	(174)	3,695	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	3,293.64	0.00	0.00	0.00	0.00	0.00	0.04	247.02	154.39
No Longer in Plan	Distribution Stations	WIND - 03D-322C Leamington Hospital - rebuild	502698	Value Driven	-	-	(176)	(199)	22	0.00	1.83	0.00	0.00	0.00	7.71	0.00	0.00	0.00	0.00	0.01	6.59	0.00	0.00	0.00	0.00	0.00	6.18	0.00	0.10
Existing Investment	Distribution Stations	WIND - 05B-201 Windsor McGregor Line - rebuild	502697	Value Driven	-	-	(711)	(1,025)	314	0.00	0.14	0.00	0.00	0.00	0.61	0.00	0.02	0.00	0.00	0.01	307.88	0.00	0.00	0.00	0.00	0.00	5.72	0.03	0.03
Existing Investment	Distribution Stations	BRAN: 12U-504 Simcoe Hunt Street South Distribution Station, Simcoe, !	100422	Mandatory	-	-	(1)	(1)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	LOND: 13O-109R Edith and Mt. Pleasant	734658	Value Driven	$ 223,019	-	267	(164)	431	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	384.46	0.00	0.00	0.00	0.00	0.00	0.04	28.83	18.02
Existing Investment	Distribution Stations	WIND - 05A-304R Sprucewood IP - Replace heater	101611	Value Driven	-	-	(263)	(263)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	BRAN: 09T-306R Front Street Avenue LP	735278	Mandatory	-	-	304	(38)	343	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	304.84	0.00	0.00	0.00	0.00	0.00	0.57	22.86	14.29
Existing Investment	Distribution Stations	CFB Station Retirement	49612	Mandatory	-	-	(77)	(77)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	LOND: 13O-401 White Oaks	735272	Value Driven	-	-	(304)	(304)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	St George & Curtis LP Repalcement Phase 2	739468	Mandatory	$ 210,235	-	(155)	(155)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	BRAN: 13U-301R Boston Class 7 Rebuild	737825	Mandatory	-	-	(35)	(35)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	King - corrosion Diamond Head Park PRS 27301037	100907	Mandatory	-	$ 104,587	(63)	(63)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	King: McPherson Drive PRS (Napanee) Frost Heave Rebuild	735797	Value Driven	-	-	(45)	(82)	36	0.00	0.08	0.00	0.00	0.00	0.32	0.00	0.00	0.00	0.00	0.00	31.03	0.00	0.00	0.00	0.00	0.00	3.09	0.00	1.97
No Longer in Plan	Distribution Stations	WATE: 17T-202 N.Dumphries Trans. Stn FIMP	735246	Value Driven	-	-	(124)	(124)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	King: Joyceville Penitentiary Unit 56	734762	Compliance	-	-	(247)	(247)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	BRAN: 11V-401R Pt Ryerse Commercial St LP	735277	Mandatory	-	-	3,382	(38)	3,420	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	3,048.36	0.00	0.00	0.00	0.00	0.00	0.04	228.63	142.89
Existing Investment	Distribution Stations	BRAN: 11U-601R Pt Ryerse Young & Rolph W Hill LP	735279	Mandatory	-	-	304	(38)	343	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	304.84	0.00	0.00	0.00	0.00	0.00	0.57	22.86	14.29
Existing Investment	Distribution Stations	BRAN: 12R-607R Tillson Ave, South of Hyman LP	735280	Mandatory	-	-	304	(38)	343	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	304.84	0.00	0.00	0.00	0.00	0.00	0.57	22.86	14.29
Existing Investment	Distribution Stations	BRAN: 12T-506R Delhi Queen & Church Stn LP	735281	Mandatory	-	-	304	(38)	343	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	304.84	0.00	0.00	0.00	0.00	0.00	0.57	22.86	14.29
Emergent	Distribution Stations	King: Ault Foods SMS (Lactalis/Parmalt - Winchester)	734768	Value Driven	-	-	(92)	(376)	285	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	282.41	0.00	0.00	0.00	0.00	0.00	0.31	0.04	1.71
Existing Investment	Distribution Stations	BRAN: 12U-607R Simcoe Queen St S & Grove LP	735282	Mandatory	-	-	304	(38)	343	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	304.84	0.00	0.00	0.00	0.00	0.00	0.57	22.86	14.29
No Longer in Plan	Distribution Stations	BRAN: 12U-609R Simcoe South & John St LP	735283	Mandatory	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WIND: 06A-605R Matchette & Prince	734666	Value Driven	-	-	(686)	(686)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WIND: 05B-205R Howard & Outer	734663	Value Driven	-	-	(152)	(156)	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	3.10	0.00	0.00	0.00	0.00	0.00	0.31	0.00	0.33
Existing Investment	Distribution Stations	HALT: Affinia Canada Corp, Rebuild	735066	Value Driven	-	-	(122)	(122)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI - US Steel Blast Furnace Atm Tank Replacement - Walpole	101140	Mandatory	-	-	(522)	(522)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI - Hillcrest Station	101345	Value Driven	-	-	(965)	(1,065)	100	0.00	1.34	0.00	0.00	0.00	5.66	0.00	3.29	0.00	0.00	74.98	9.35	0.00	0.00	0.00	0.00	0.00	5.29	0.00	0.09
No Longer in Plan	Distribution Stations	WIND: 04E-438C Protolight Farms	734654	Value Driven	-	-	(152)	(194)	42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	36.23	0.00	0.00	0.00	0.00	0.00	3.60	0.00	2.31
Emergent	Distribution Stations	King: HOLY CROSS CATHOLIC SECONDARY (Kingston)	734771	Value Driven	-	-	0	(0)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WIND: 06B-607I Ford/Nemak Station Rebuild	502950	Value Driven	-	-	(602)	(602)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	King: Aragon PRS Hazardous Area Mitigation (Kingston)	734772	Value Driven	-	-	(36)	(36)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	BRAN: 13U-603R Waterford Temperence & Leamon LP	735284	Mandatory	-	-	304	(38)	343	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	304.84	0.00	0.00	0.00	0.00	0.00	0.57	22.86	14.29
No Longer in Plan	Distribution Stations	TIMM: Evergreen Greenhouse SMS Retirement	734573	Mandatory	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	King: Cornwall Centre PRS	734779	Value Driven	-	-	(166)	(166)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	CHAT - 08H-302C Greenhill Produce - rebuild and heater addition	502775	Value Driven	$ 440,554	-	121	(330)	451	0.00	0.11	0.00	0.00	0.00	0.47	0.00	0.00	0.00	0.00	0.00	422.91	0.00	0.00	0.00	0.00	0.00	0.49	0.00	26.91
Emergent	Distribution Stations	King: Woodbine @NC Easement PRS	734780	Value Driven	-	-	(217)	(217)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	BRAN: 15U-301R St Paul & Dublin LP	735285	Mandatory	-	-	304	(38)	343	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	304.84	0.00	0.00	0.00	0.00	0.00	0.57	22.86	14.29
Emergent	Distribution Stations	King: GT Machine SMS	734760	Value Driven	-	-	(95)	(95)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00
Existing Investment	Distribution Stations	LOND - Mitchell Station Rebuild - London	48376	Value Driven	-	-	(203)	(203)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	King: Maple Ridge Farms DRS	734756	Value Driven	-	-	(212)	(212)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	King: Finch Concession 4-5 DRS (2-94-01-038)	734755	Value Driven	-	-	44	(227)	270	0.00	1.72	0.00	0.00	0.00	7.28	0.00	0.04	0.00	0.00	0.01	261.36	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.03
Emergent	Distribution Stations	King: Crysler DRS Rebuild (29401023)	734754	Value Driven	-	$ 64,246	327	(38)	366	0.00	1.72	0.00	0.00	0.00	7.28	0.00	0.06	0.00	0.00	0.01	356.21	0.00	0.00	0.00	0.00	0.00	0.39	0.00	0.04
No Longer in Plan	Distribution Stations	TBAY: Arthur St at Cooper Rd PRS Rebuild	735729	Value Driven	-	-	(311)	(311)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	LOND: 21L-201 Goderich Gate	735155	Value Driven	-	-	(1,064)	(1,099)	35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.92	30.51	0.00	0.00	0.00	0.00	0.00	0.57	0.00	0.18
No Longer in Plan	Distribution Stations	THUN: Gorevale Road PRS Station Relocation	735707	Value Driven	-	-	(197)	(197)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Mountdale at Francis DRS Rebuild	735635	Value Driven	-	-	(290)	(290)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Dewe St DRS Relocation	735634	Value Driven	-	-	(313)	(313)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	TBAY: Balsam St TBS Filter	735633	Mandatory	-	-	(83)	(83)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Burwood Rd TBS Filter	735632	Mandatory	-	-	(48)	(48)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	TBAY: Paquette Road Station Rebuild	735631	Value Driven	-	-	(638)	(649)	10	0.00	1.45	0.00	0.00	0.00	6.11	0.00	0.05	0.00	0.00	0.00	0.43	0.00	0.00	0.00	0.00	0.00	0.36	0.00	2.05
Existing Investment	Distribution Stations	SARN: 14F-503R Point Edward Victoria and St. Clair Reg Stn	734696	Value Driven	-	-	194	(122)	317	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	282.12	0.00	0.00	0.00	0.00	0.00	0.03	21.16	13.22
Existing Investment	Distribution Stations	SARN: 11H-201R Oil Spring Reg Stn	734693	Value Driven	-	-	214	(128)	343	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	304.84	0.00	0.00	0.00	0.00	0.00	0.57	22.86	14.29
Existing Investment	Distribution Stations	SARN: 13F-323R McPlank	734680	Value Driven	-	-	(281)	(281)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	SARN: 12F-201I Suncor Ethanol	734679	Value Driven	-	-	(149)	(149)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	SARN: 12F-106I Suncor Hydrogen/Air Products	734662	Value Driven	-	-	(841)	(841)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Fisher 621 PRS Rebuild Program	735629	Value Driven	-	-	(575)	(575)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	BRAN: 15V-406R Mohawk Brighton LP	735287	Mandatory	-	-	304	(38)	343	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	304.84	0.00	0.00	0.00	0.00	0.00	0.57	22.86	14.29
Existing Investment	Distribution Stations	BRAN: 15U-308R Brantford Grand & Jubilee LP	735313	Mandatory	-	-	260	(33)	293	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	261.10	0.00	0.00	0.00	0.00	0.00	0.03	19.58	12.24
Emergent	Distribution Stations	BRAN: 15U-311R Brantford Waterloo & William LP	735316	Mandatory	-	-	260	(33)	293	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	261.10	0.00	0.00	0.00	0.00	0.00	0.03	19.58	12.24
Emergent	Distribution Stations	BRAN: 15V-407R Bishop & Blossie LP	735318	Mandatory	-	-	260	(33)	293	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	261.10	0.00	0.00	0.00	0.00	0.00	0.03	19.58	12.24
Existing Investment	Distribution Stations	BRAN: 15V-408R Brighton & Superior LP	735319	Mandatory	-	-	260	(33)	293	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	261.10	0.00	0.00	0.00	0.00	0.00	0.03	19.58	12.24
No Longer in Plan	Distribution Stations	BRAN: 11V-202R Pt Dover Nelson & George St LP	735326	Mandatory	-	-	328	(41)	370	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	329.36	0.00	0.00	0.00	0.00	0.00	0.04	24.70	15.44
No Longer in Plan	Distribution Stations	BRAN: 11V-204R Pt Dover Clinton & St Patrick LP	735327	Mandatory	-	-	329	(41)	371	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.24	0.00	0.00	0.00	329.36	0.00	0.00	0.00	0.00	0.00	0.04	24.70	15.44
No Longer in Plan	Distribution Stations	BRAN: 09T-303R Church St & Erie Ave LP	735328	Mandatory	-	-	328	(41)	370	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	329.36	0.00	0.00	0.00	0.00	0.00	0.04	24.70	15.44
No Longer in Plan	Distribution Stations	WATE: 09T-307R Ellis & Alley St LP	735329	Mandatory	-	-	328	(41)	370	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	329.36	0.00	0.00	0.00	0.00	0.00	0.04	24.70	15.44
No Longer in Plan	Distribution Stations	BRAN: 12R-302R Victoria St & Niagara St Station LP	735330	Mandatory	-	-	328	(41)	370	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	329.36	0.00	0.00	0.00	0.00	0.00	0.04	24.70	15.44

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
No Longer in Plan	Distribution Stations	BRAN: 12R-303R Tillson Ave Dist Station LP	735331	Mandatory	-	-	328	(41)	370	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	329.36	0.00	0.00	0.00	0.00	0.00	0.04	24.70	15.44
No Longer in Plan	Distribution Stations	BRAN: 12U-501 Simcoe Queen St South of Hwy 3 (2nd Stage) LP	735332	Mandatory	-	-	328	(41)	370	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	329.36	0.00	0.00	0.00	0.00	0.00	0.04	24.70	15.44
No Longer in Plan	Distribution Stations	BRAN: 12U-602R Simcoe Union & Talbot Stn LP	735333	Mandatory	-	-	328	(41)	370	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	329.36	0.00	0.00	0.00	0.00	0.00	0.04	24.70	15.44
No Longer in Plan	Distribution Stations	BRAN: 12U-606R Simcoe Metcalfe & Robinson LP	735334	Mandatory	-	-	3,654	(41)	3,695	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	3,293.64	0.00	0.00	0.00	0.00	0.00	0.04	247.02	154.39
Existing Investment	Distribution Stations	BRAN: 11V-101 Port Dover South Distribution Station, Port Dover, Static	100627	Mandatory	-	-	(37)	(37)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Vermillion Bay PCS, Boiler Replacement	733772	Value Driven	-	-	(129)	(138)	9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	3.10	0.00	0.00	0.00	0.00	0.00	5.29	0.00	0.33
Existing Investment	Distribution Stations	TBAY: Kenora Airport Rd, Boiler Replacement	733876	Value Driven	-	-	(65)	(65)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Geraldton TBS, Boiler Replacement	733875	Value Driven	-	-	(65)	(65)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Balmertown - Goldcorp SMS, Boiler Replacement	733872	Value Driven	-	-	(101)	(101)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	BRAN: 12S-101 Tillsonburg Potter's Road Distribution Station, Tillsonbur	100550	Mandatory	-	-	(19)	(19)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	TBAY: Clark & Niven DRS Rebuild	48527	Value Driven	-	-	(100)	(433)	332	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	329.69	0.00	0.00	0.00	0.00	0.00	0.36	0.05	1.99
Emergent	Distribution Stations	LOND: 12M-402R Glendon Dr. Reg Station Replacement	738695	Value Driven	$ 63,994	-	(33)	(33)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Nipigon TBS, Boiler Replacement	733870	Value Driven	-	-	(66)	(66)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	LOND: 14O-619I 3M Customer Station Rebuild; 528	49861	Value Driven	-	-	(234)	(234)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	LOND: 14O-603I 3M Customer Station Rebuild	49862	Mandatory	-	-	(234)	(234)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Belrose PCS, Boiler Replacement	733869	Value Driven	-	-	(426)	(426)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	13O-113R Bathurst & Talbot	100999	Value Driven	$ 223,019	-	552	(167)	719	0.00	0.28	0.00	0.00	0.00	1.19	0.00	0.00	0.00	0.00	0.00	388.31	0.00	0.00	0.00	0.00	0.00	4.21	144.17	180.63
Existing Investment	Distribution Stations	15R-604R Young & Peel LP Stn	100998	Value Driven	-	-	(99)	(103)	4	0.00	0.21	0.00	0.00	0.00	0.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.33	0.00	0.00
No Longer in Plan	Distribution Stations	13P-101R Sovereign & Gore	100996	Value Driven	-	-	(1,164)	(1,206)	43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.23	0.00	0.00	0.00	0.00	0.00	6.18	0.00	0.10
Existing Investment	Distribution Stations	TBAY: Ignace TBS, Boiler Replacement	733867	Value Driven	-	-	(68)	(68)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: McIrvine TBS, Boiler Replacement	733866	Value Driven	-	-	(68)	(68)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	TBAY: 33-23-700 Arthur St TBS, Thunder Bay, Station Rebuild	100918	Mandatory	-	-	(1,541)	(1,656)	114	0.00	11.88	0.00	0.00	0.00	50.11	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00	42.20	0.00	9.88
No Longer in Plan	Distribution Stations	TBAY: Kraft SMS Retirement	502824	Value Driven	-	-	(132)	(132)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Dryden Domtar SMS, Station Modifications	100938	Value Driven	-	-	(113)	(113)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Longlac TBS, Heater Replacement	100945	Value Driven	-	-	(167)	(169)	1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.61	0.00	0.00	0.00	0.00	0.00	0.33	0.00	0.02
No Longer in Plan	Distribution Stations	TBAY: 500 Toledo St MUB Rebuild	734565	Value Driven	-	-	(130)	(130)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: English River PCS Rebuild	503174	Value Driven	-	-	(1,481)	(1,533)	52	0.00	5.92	0.00	0.00	0.00	24.96	0.00	0.03	0.00	0.00	0.00	6.10	0.00	0.00	0.00	0.00	0.00	5.72	0.00	9.24
Existing Investment	Distribution Stations	BRAN: 16U-601 Brantford Gate Station, Station Rebuild (Capital Mainter	103426	Value Driven	$ 1,063,530	-	(9,084)	(9,130)	46	0.00	2.17	0.00	0.00	0.00	9.16	0.00	0.02	0.00	0.00	11.92	9.58	0.00	0.00	0.00	0.00	0.00	9.65	0.00	3.34
Existing Investment	Distribution Stations	SARN: 13F-220R Vidal St	734676	Value Driven	-	-	(6,564)	(6,564)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Wright at O'Brien DRS Pipe Supports	733372	Mandatory	-	-	(17)	(17)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	TBAY: New Station at Mercury Ave & Maple Station Retirement (Atikoka	733375	Value Driven	-	-	(317)	(649)	332	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	329.69	0.00	0.00	0.00	0.00	0.00	0.36	0.05	1.99
Emergent	Distribution Stations	NBAY: Balls Dr TBS - Bracebridge, Boiler Replacement	733817	Value Driven	-	-	(68)	(68)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	McCreedy West Stn., Sudbury	49678	Mandatory	-	-	(14)	(14)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NE: Espanola DRS & Domtar SMS, Station Rebuild	733843	Value Driven	-	-	(791)	(852)	61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.75	56.42	0.00	0.00	0.00	0.00	0.00	3.61	0.00	0.17
Existing Investment	Distribution Stations	SUD: Copper Cliff TBS, Boiler Replacement	733841	Value Driven	-	-	(64)	(64)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	NE: 43202154 - Bil-Mur PRS, Rebuild	501161	Value Driven	-	-	(131)	(166)	35	0.00	0.16	0.00	0.00	0.00	0.66	0.00	0.02	0.00	0.00	0.01	33.27	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.03
Emergent	Distribution Stations	Sarnia Industrial Station 2029 Rebuild	735022	Value Driven	-	-	(6,746)	(6,746)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	NE: 43202054 Inco Smelter, Station Modifications	501160	Value Driven	-	-	54	(286)	340	0.00	0.94	0.00	0.00	0.00	3.97	0.00	0.04	0.00	0.00	0.01	332.76	0.00	0.00	0.00	0.00	0.00	1.85	0.00	0.03
Emergent	Distribution Stations	LUG - ERX Cloudlink Modem Replacement	739582	Mandatory	$ 10,023	$ 34,845	(28)	(28)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WIND - 06B-403 California Ave station rebuild	503332	Value Driven	$ 128,913	-	(6,115)	(6,115)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	LOND: 14O-503R Highbury and Cheapside Dist Stn	734674	Value Driven	$ 128,913	-	(5,027)	(6,090)	1,063	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	332.66	0.00	0.00	0.00	0.00	0.00	730.78	0.00	0.00
Existing Investment	Distribution Stations	WATE: Mt Elgin Dist Stn, Mt Elgin, Station	100240	Value Driven	-	-	(51)	(85)	34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.53	0.00	0.00	0.00	0.00	0.00	0.33	0.00	0.09
Existing Investment	Distribution Stations	WATE: 17T-202 North Dumfries Distribution Station, North Dumfries, St	100615	Mandatory	-	-	(245)	(245)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WATE: 18U-504 Cambridge East Distribution Station, Cambridge, Statior	100617	Value Driven	-	$ 448,229	(309)	(789)	480	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.58	363.33	0.00	0.00	0.00	0.00	0.00	37.05	0.00	37.94
Existing Investment	Distribution Stations	WATE: 23Q-301 Harriston Gate Station, Harriston, Station Rebuild Obso	100912	Value Driven	-	$ 747,048	(653)	(690)	37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	36.23	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.10
Existing Investment	Distribution Stations	WATE: 22T-501R Alma Distribution Station, Alma, Station Rebuild (Capit:	503215	Value Driven	-	-	(247)	(247)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HALT-440 Harrop	101092	Value Driven	-	-	83	(230)	313	0.00	1.45	0.00	0.00	0.00	6.11	0.00	0.02	0.00	0.00	0.01	305.14	0.00	0.00	0.00	0.00	0.00	0.04	0.03	0.03
Emergent	Distribution Stations	BRAN: 12U-514R 510 Queensway St W Class 7 Rebuild, Corrosion and Le	738666	Mandatory	$ 25,783	-	(19)	(19)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WATE: 18U-506R Bishop & King LP	735325	Mandatory	-	-	281	(35)	317	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	282.12	0.00	0.00	0.00	0.00	0.00	0.03	21.16	13.22
Existing Investment	Distribution Stations	WATE: 18U-418R 122 Dolph St N LP	735324	Mandatory	-	-	260	(33)	293	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	261.10	0.00	0.00	0.00	0.00	0.00	0.03	19.58	12.24
Emergent	Distribution Stations	WATE: 26Q-271 Allan Park, Class 7 Station Rebuild, class c leak repairs ai	738476	Mandatory	$ 64,456	-	(48)	(48)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	WATE: 18U-405R Church & Queenston LP	735323	Mandatory	-	-	2,896	(33)	2,929	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	2,610.96	0.00	0.00	0.00	0.00	0.00	0.03	195.82	122.39
Existing Investment	Distribution Stations	WATE: 18U-403R Agnes & William LP	735322	Mandatory	-	-	2,896	(33)	2,929	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	2,610.96	0.00	0.00	0.00	0.00	0.00	0.03	195.82	122.39
Existing Investment	Distribution Stations	WATE: 17U-214R Middleton St at Waterworks LP	735321	Mandatory	-	-	260	(33)	293	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	261.10	0.00	0.00	0.00	0.00	0.00	0.03	19.58	12.24
Existing Investment	Distribution Stations	WATE: 17U-211R Stanley @ Glenmorris LP	735320	Mandatory	-	-	260	(33)	293	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	261.10	0.00	0.00	0.00	0.00	0.00	0.03	19.58	12.24
Existing Investment	Distribution Stations	WATE: 18U-407R Church & Sherring LP	735310	Mandatory	-	-	261	(33)	293	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	261.10	0.00	0.00	0.00	0.00	0.00	0.49	19.58	12.24
Existing Investment	Distribution Stations	WATE: 18U-220R Bechtel & Millvue LP	735308	Mandatory	-	-	261	(33)	293	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	261.10	0.00	0.00	0.00	0.00	0.00	0.49	19.58	12.24
Existing Investment	Distribution Stations	WATE: 18U-205R Hungerford & Walker LP	735307	Mandatory	-	-	2,896	(33)	2,929	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	2,610.96	0.00	0.00	0.00	0.00	0.00	0.03	195.82	122.39
Emergent	Distribution Stations	WATE: 17U-201R Salsbury Ave LP	735288	Mandatory	-	-	343	(0)	343	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	304.84	0.00	0.00	0.00	0.00	0.00	0.57	22.86	14.29
Existing Investment	Distribution Stations	WATE: 12T-102 Norwich-Middleton Town Stn. FIMP	735269	Value Driven	-	-	(78)	(78)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WATE: 30Q-105C Sutherland Downs Pit FIMP	735263	Value Driven	-	-	(72)	(72)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WATE: 30N-501 Southhampton Gate Stn. FIMP	735262	Value Driven	-	-	(72)	(72)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WATE: 22S-402 Moorefield Dist. Stn. FIMP	735260	Value Driven	-	-	(72)	(72)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WATE: 19U-601R Rozelle Rd. Dist. Stn FIMP	735258	Value Driven	-	-	(72)	(72)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	BRAN: 13T-101 Norwich Trans Stn . FIMP	735255	Value Driven	-	-	(91)	(91)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	WATE: 18T-402 Mannheim Trans Stn	735252	Value Driven	-	-	(99)	(99)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI-Summit Trans Stn,	101094	Value Driven	-	-	(225)	(225)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.25	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.00
Emergent	Distribution Stations	HAMI: National Steel Car, Telemetry	739819	Value Driven	$ 31,399	-	(23)	(23)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI - Diltz Rd IP North	101101	Mandatory	-	-	(307)	(307)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI: 16Y-106R Kenora & Bancroft, Hamilton, Vault Station Rebuild	101103	Value Driven	-	-	173	(414)	587	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.06	0.00	0.00	0.00	362.40	0.00	0.00	0.00	0.00	0.00	185.27	0.00	3.50
Existing Investment	Distribution Stations	HAMI: Temple Canada, Maintenance	735057	Mandatory	-	-	(30)	(30)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI: Birmingham and Burlington, Maintenance	735058	Value Driven	-	-	(243)	(243)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI: 17X-321R Industrial St, Hamilton, Vault Station Rebuild	101126	Value Driven	-	-	137	(414)	551	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	362.30	0.00	0.00	0.00	0.00	0.00	185.27	0.00	3.50
Existing Investment	Distribution Stations	SARN: 13F-402 Shell Canada	734685	Value Driven	-	-	(208)	(208)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TBAY: Kenora TBS, Boiler Replacement	733865	Value Driven	-	-	(106)	(106)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	SUDB: 44301001 Azilda DRS, CWT Repair	738783	Value Driven	$ 44,668	-	(33)	(33)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NE: 45101125 - Essar #7 BF SMS, Gear Operator Replacement	502659	Mandatory	$ 12,891	-	77	(9)	86	0.00	1.97	0.00	0.00	0.00	8.33	0.00	0.00	0.00	0.00	0.00	65.87	0.00	0.00	0.00	0.00	0.00	0.42	0.00	8.94
Existing Investment	Distribution Stations	NE: 45401095 - Great Northern Rd TBS, Boiler Replacement	502661	Value Driven	-	-	(237)	(322)	85	0.00	1.83	0.00	0.00	0.00	7.71	0.00	0.00	0.00	0.00	0.00	65.87	0.00	0.00	0.00	0.00	0.00	0.42	0.00	8.94
Existing Investment	Distribution Stations	NE: 43201030 - Coniston Primary, Control Valve Modifications	736083	Value Driven	-	-	(172)	(172)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NE: 45101001 - Sault Primary, Control Valve Modifications	736082	Value Driven	-	-	(134)	(134)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	SSM: Goulais Ave TBS Algoma 4, Station Modifications	736079	Mandatory	-	$ 74,705	(45)	(45)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI: 12Z-301 Port Maitland Rymer Station, Haldimand, Heater Installa	103529	Value Driven	-	-	(413)	(414)	0	0.00	0.02	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00
Existing Investment	Distribution Stations	NE: 43501002 - Coniston DRS, Rebuild	101072	Value Driven	-	$ 298,819	(41)	(179)	138	0.00	18.28	0.00	0.00	0.00	77.10	0.00	0.00	0.00	0.00	0.00	35.94	0.00	0.00	0.00	0.00	0.00	6.67	0.00	0.11
Existing Investment	Distribution Stations	NE: 13403001 - Vale Totten Mine, Rebuild	101068	Value Driven	-	-	(602)	(688)	86	0.00	1.97	0.00	0.00	0.00	8.33	0.00	0.00	0.00	0.00	0.00	65.87	0.00	0.00	0.00	0.00	0.00	0.42	0.00	8.94
Existing Investment	Distribution Stations	SUD: Azilda DRS, Boiler Replacement	733857	Value Driven	-	-	(62)	(62)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	SUD: Kelly Lake TBS, Boiler Replacement	733763	Value Driven	-	-	(68)	(113)	45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	3.35	0.00	0.00	0.00	0.00	0.00	40.96	0.00	0.36
Existing Investment	Distribution Stations	SUD: Kukagami TBS, Boiler Replacement	733856	Value Driven	-	-	(62)	(62)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NE: 43202064 Vale Divisional Shops PRS Replacement	49611	Value Driven	-	-	32	(284)	316	0.00	1.45	0.00	0.00	0.00	6.11	0.00	0.02	0.00	0.00	0.00	305.14	0.00	0.00	0.00	0.00	0.00	1.71	0.00	1.84
Existing Investment	Distribution Stations	SSM: Blind River TBS, Boiler Replacement	733854	Value Driven	-	-	(95)	(95)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	SUD: Inco North Mine SMS, Boiler Replacement	733853	Value Driven	-	-	(62)	(62)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	SUDB: 13200177 - Interpaving SMS, CWT Remove & refurb	738782	Value Driven	-	-	(8)	(8)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NE: 43202063 - Vale Engineering & Exploration, Rebuild/Relocation	49894	Value Driven	-	-	(119)	(157)	39	0.00	1.45	0.00	0.00	0.00	6.11	0.00	0.00	0.00	0.00	0.00	30.79	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.18
Existing Investment	Distribution Stations	SUD: Walden TBS, Boiler Replacement	733814	Value Driven	-	-	(70)	(70)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	SUD: Chelmsford, Boiler Replacement	733765	Value Driven	-	-	(68)	(109)	41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	3.10	0.00	0.00	0.00	0.00	0.00	37.91	0.00	0.33
Existing Investment	Distribution Stations	SSM: Elliot Lake TBS, Boiler Replacement	733852	Value Driven	-	-	(98)	(98)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	SUD: Coniston TBS, Boiler Replacement	733813	Value Driven	-	-	(70)	(70)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	SUD: Maley Dr TBS, Boiler Replacement	733767	Value Driven	-	-	520	(109)	629	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	3.10	0.00	0.00	0.00	0.00	0.00	625.96	0.00	0.33
Existing Investment	Distribution Stations	TIMM: Iroquois Falls TBS, Station Rebuild	734941	Value Driven	-	-	(1,268)	(1,281)	12	0.00	1.24	0.00	0.00	0.00	5.24	0.00	0.04	0.00	0.00	0.00	2.69	0.00	0.00	0.00	0.00	0.00	1.47	0.00	1.58
Existing Investment	Distribution Stations	TIMM: Tembec Spruce Falls SMS, Rebuild	733880	Value Driven	-	-	(1,298)	(1,298)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
Existing Investment	Distribution Stations	TIMM: 45-22-700 Goldcorp Dome Mine SMS, Rebuild	101158	Value Driven	-	$ 262,499	(1,451)	(1,564)	113	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.84	0.00	0.00	0.00	3.31	0.00	0.00	0.00	0.00	0.00	4.22	12.35	88.36
Existing Investment	Distribution Stations	TIMM: Hwy 655 TBS, Boiler Replacement	733877	Value Driven	-	-	(108)	(108)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI: 16X-106R King St E, Dundas, Vault Station Rebuild	101130	Value Driven	-	-	137	(414)	551	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	362.30	0.00	0.00	0.00	0.00	0.00	185.27	0.00	3.50
Existing Investment	Distribution Stations	TIMM: Moneta TBS, Boiler Replacement	733874	Value Driven	-	-	(95)	(95)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TIMM: Kapuskasing TBS, Boiler Replacement	733873	Value Driven	-	-	(261)	(261)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TIMM: Dalton TBS (Mcbride St S.), Station Rebuild and Boiler Replacem	733871	Value Driven	-	-	(423)	(423)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TIMM: Schumacher TBS, Boiler Replacement	733868	Value Driven	-	-	(68)	(68)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TIMM: Matheson TBS, Boiler Replacement	733864	Value Driven	-	-	(70)	(70)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TIMM: Glencore Mine SMS, Boiler Replacement	733768	Value Driven	-	-	(102)	(106)	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	3.35	0.00	0.00	0.00	0.00	0.00	0.33	0.00	0.36
Existing Investment	Distribution Stations	TIMM: South Porcupine/Crawford TBS, Boiler Replacement	733769	Value Driven	-	-	(152)	(152)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TIMM: Porcupine PCS, Boiler Replacement	733770	Value Driven	-	-	(97)	(142)	45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	3.35	0.00	0.00	0.00	0.00	0.00	40.96	0.00	0.36
Existing Investment	Distribution Stations	TIMM: Kirkland Lake TBS, Boiler Replacement	733771	Value Driven	-	-	(103)	(113)	10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	3.35	0.00	0.00	0.00	0.00	0.00	5.72	0.00	0.36
Existing Investment	Distribution Stations	TIMM: Cochrane TBS, Boiler Replacement	733773	Value Driven	-	-	(101)	(109)	9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	3.10	0.00	0.00	0.00	0.00	0.00	5.29	0.00	0.33
Existing Investment	Distribution Stations	TIMM: Swastika TBS, Station Rebuild	100922	Mandatory	-	-	(398)	(519)	122	0.00	1.97	0.00	0.00	0.00	8.33	0.00	3.65	0.00	0.00	0.00	33.05	0.00	0.00	0.00	0.00	0.00	36.02	0.00	38.49
Existing Investment	Distribution Stations	TIMM: 45-22-702 Kirkland Lake (Northland) Power SMS Rebuild	502088	Value Driven	-	-	(1,097)	(1,097)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	TIMM: Malette Kraft SMS Retirement	734572	Mandatory	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TIMM: Hallnor Mine PRS Retirement	734574	Mandatory	-	-	(41)	(41)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TIMM: Munoro Mine SMS Retirement	734576	Mandatory	-	-	(29)	(29)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	TIMM: Porcupine PCS, Heater Replacement	739227	Value Driven	$ 59,300	-	(44)	(44)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	TIMM: Opasatika TBS Rebuild	734623	Value Driven	-	-	(331)	(338)	8	0.00	1.06	0.00	0.00	0.00	4.48	0.00	0.04	0.00	0.00	0.00	0.29	0.00	0.00	0.00	0.00	0.00	0.24	0.00	1.39
Existing Investment	Distribution Stations	TIMM: Mattice TBS Rebuild	734624	Value Driven	-	-	(306)	(313)	7	0.00	0.98	0.00	0.00	0.00	4.15	0.00	0.03	0.00	0.00	0.00	0.27	0.00	0.00	0.00	0.00	0.00	0.23	0.00	1.29
Existing Investment	Distribution Stations	TIMM: Val Gagne TBS Rebuild	734625	Value Driven	-	-	(450)	(460)	10	0.00	1.45	0.00	0.00	0.00	6.11	0.00	0.05	0.00	0.00	0.00	0.40	0.00	0.00	0.00	0.00	0.00	0.33	0.00	1.90
Existing Investment	Distribution Stations	TIMM: Fauquier TBS Rebuild	734626	Value Driven	-	-	(357)	(365)	8	0.00	1.15	0.00	0.00	0.00	4.85	0.00	0.04	0.00	0.00	0.00	0.32	0.00	0.00	0.00	0.00	0.00	0.26	0.00	1.51
Existing Investment	Distribution Stations	TIMM: Smooth Rock Falls CMS, TBS, and DRS Relocations/Retirements	734628	Value Driven	-	-	(1,226)	(1,916)	691	0.00	0.00	0.00	0.00	0.00	0.00	0.00	308.60	0.00	0.00	74.95	284.95	0.00	0.00	0.00	0.00	0.00	5.29	0.17	16.78
Existing Investment	Distribution Stations	TIMM: 45-23-700 2881 Hwy 655 TBS Low-Piping Modifications	502086	Value Driven	-	-	(278)	(278)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00
Existing Investment	Distribution Stations	TIMM: 45-23-701 Porcupine Primary Low-Piping Modifications	502087	Value Driven	-	-	(278)	(278)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00
Existing Investment	Distribution Stations	TIMM: Monteith CMS	735730	Value Driven	-	-	(790)	(828)	37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.04	0.00	0.00	0.00	0.00	0.00	4.22	0.00	0.20
Existing Investment	Distribution Stations	TIMM: Glencore Concentrator SMS, Boiler Replacement	503742	Value Driven	-	-	(129)	(133)	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	3.35	0.00	0.00	0.00	0.00	0.00	0.33	0.00	0.36
Existing Investment	Distribution Stations	TIMM: Kirkland Lake CMS (Kenogami) - Long-Term Odorant Solution	734943	Value Driven	-	-	(346)	(346)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NBAY: Haileybury TBS, Boiler Replacement	733759	Value Driven	-	-	(131)	(142)	10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	3.62	0.00	0.00	0.00	0.00	0.00	6.18	0.00	0.38
Existing Investment	Distribution Stations	NBAY: Sturgeon Falls TBS, Boiler Replacement	733760	Value Driven	-	-	(106)	(116)	10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	3.62	0.00	0.00	0.00	0.00	0.00	6.18	0.00	0.38
Existing Investment	Distribution Stations	NBAY: Emsdale CMS, Boiler Replacement	733851	Value Driven	-	-	(64)	(64)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NBAY: West St TBS, Boiler Replacement	733766	Value Driven	-	-	(125)	(167)	41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	3.10	0.00	0.00	0.00	0.00	0.00	37.91	0.00	0.33
Existing Investment	Distribution Stations	NBAY: Ferguson Road, Boiler Replacement	733820	Value Driven	-	-	(68)	(68)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NBAY: New Liskeard TBS, Boiler Replacement	733821	Value Driven	-	-	(103)	(103)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NBAY: Earlton TBS, Boiler Replacement	733822	Value Driven	-	-	(68)	(68)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NBAY: Mattawa TBS, Boiler Replacement	733796	Value Driven	-	-	(70)	(70)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NBAY: Eloy TBS, Boiler Replacement	733764	Value Driven	-	-	(147)	(192)	45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	3.35	0.00	0.00	0.00	0.00	0.00	40.96	0.00	0.36
Existing Investment	Distribution Stations	NBAY: Ravensglen TBS, Boiler Replacement	733823	Value Driven	-	-	(152)	(152)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NE: 43601001 - Balls Dr TBS, Rebuild	502704	Value Driven	-	-	(573)	(674)	102	0.00	1.34	0.00	0.00	0.00	5.66	0.00	0.00	0.00	0.00	0.00	84.73	0.00	0.00	0.00	0.00	0.00	1.95	0.00	7.83
Existing Investment	Distribution Stations	NE: 42601002 - Englehart TBS, Relocation	101073	Value Driven	-	-	(1,317)	(1,407)	90	0.00	10.18	0.00	0.00	0.00	42.93	0.00	0.00	0.00	0.00	0.00	36.23	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.29
Existing Investment	Distribution Stations	NBAY: Warren TBS, Boiler Replacement	735030	Value Driven	-	-	(66)	(66)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NBAY: West Ferris TBS, Boiler Replacement	733838	Value Driven	-	-	(66)	(66)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NBAY: TCPL Co-gen North Bay, Boiler Replacement	733839	Value Driven	-	-	(101)	(101)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NBAY: Madill TBS _ Huntsville, Boiler Replacement	733840	Value Driven	-	-	(101)	(101)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI: 16X-225R South Bend & Upper James Station, Hamilton, Vault Sta	101131	Value Driven	-	-	137	(414)	551	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	362.30	0.00	0.00	0.00	0.00	0.00	185.27	0.00	3.50
Existing Investment	Distribution Stations	NE: 44702001 - Rutherglen TBS, Rebuild	502663	Value Driven	-	-	(352)	(383)	32	0.00	0.14	0.00	0.00	0.00	0.61	0.00	0.02	0.00	0.00	0.01	30.79	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.03
Existing Investment	Distribution Stations	NBAY: Callander TBS, Boiler Replacement	733842	Value Driven	-	-	(64)	(64)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	HAMI - Bancroft and Nash Vault Station	101132	Value Driven	-	-	137	(414)	551	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	362.30	0.00	0.00	0.00	0.00	0.00	185.27	0.00	3.50
Existing Investment	Distribution Stations	HAMI - Ferrie and Wellington Vault Station	101133	Value Driven	-	-	137	(414)	551	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	362.30	0.00	0.00	0.00	0.00	0.00	185.27	0.00	3.50
Existing Investment	Distribution Stations	NBAY: Widdifield TBS, Boiler Replacement	733795	Value Driven	-	-	(70)	(70)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Stations	NE: 42801004 - Cobalt TBS, Rebuild	502662	Value Driven	-	-	(419)	(455)	36	0.00	0.16	0.00	0.00	0.00	0.66	0.00	0.00	0.00	0.00	0.01	33.27	0.00	0.00	0.00	0.00	0.00	0.36	0.00	1.99
Existing Investment	Distribution Stations	NBAY: Englehart TBS, Boiler Replacement	733761	Value Driven	-	-	(110)	(116)	6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	3.62	0.00	0.00	0.00	0.00	0.00	1.85	0.00	0.38
Existing Investment	Distribution Stations	NBAY: South River TBS, Boiler Replacement	733797	Value Driven	-	-	(70)	(70)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Guelph Rectifier 148 and 168 Repairs	739226	Value Driven	$ 38,674	-	(29)	(29)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	NPS 10 Owen Sound Section 3 Dig	739943	Value Driven	$ 644,564	-	(589)	(589)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	NPS 12 Marten River Lateral Dig	739945	Value Driven	$ 327,602	-	(245)	(245)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	North Shore Section A Integrity Digs	739664	Value Driven	$ 3,662,368	-	(2,743)	(2,743)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	NPS 12 Northland Power Integrity Dig	739684	Value Driven	$ 379,490	-	(299)	(299)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	NPS 6 St. Mary's Digs 2023	738943	Compliance	$ 989,883	-	(824)	(824)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Norwich South & Delhi 6 Phase 2 Int. Digs	739467	Compliance	$ 5,180,422	-	(3,880)	(3,880)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	NPS 4 New Liskeard Wabi Creek Replacement	739567	Value Driven	$ 2,317,664	-	(1,736)	(1,736)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	SARN - Eastlawn Ave and Kember Ave Leakage - Sarnia BU	101214	Value Driven	-	-	(692)	(836)	144	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.35	0.00	0.00	0.04	3.40	0.00	0.00	0.00	0.00	0.00	1.85	123.51	2.83
No Longer in Plan	Distribution Pipe	HAMI: Fleming Ave, Dundas, BU Replacement	733650	Value Driven	-	-	(70)	(70)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	SARN - Smith Line Leakage - Sombra BU	101210	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	HAMI: Osler Dr @ Rail Trail, Dundas, BU Replacement	733649	Value Driven	-	-	102	(84)	186	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.35	0.00	0.00	1.24	3.40	0.00	0.00	0.00	0.00	0.00	42.20	123.51	2.83
Existing Investment	Distribution Pipe	SARN - Christina St at Highbury Pk Leakage - Sarnia BU	101194	Value Driven	-	-	(7)	(129)	122	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.58	0.00	0.00	0.04	2.91	0.00	0.00	0.00	0.00	0.00	0.31	105.80	2.42
Existing Investment	Distribution Pipe	SARN - Lakeshore Rd. and Modeland Rd Leakage - Sarnia BU	101193	Value Driven	-	-	(255)	(450)	195	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.43	0.00	0.00	0.04	60.97	0.00	0.00	0.00	0.00	0.00	1.71	114.31	6.29
Existing Investment	Distribution Pipe	BRAN - Connaught Ave. (Hwy 3 to Delcrest) Repl. BU - Delhi	48956	Value Driven	-	-	(49)	(250)	201	0.00	0.83	0.00	0.00	0.06	3.50	0.00	0.00	0.00	0.00	8.14	33.53	0.00	0.00	0.00	0.00	0.00	39.06	114.31	1.90
No Longer in Plan	Distribution Pipe	LOND - Wharncliffe & Baseline BU - London	48918	Value Driven	-	-	122	(152)	275	0.00	18.28	0.00	0.00	36.82	77.10	0.00	12.35	0.00	0.00	0.04	3.40	0.00	0.00	0.00	0.00	0.00	0.36	123.51	2.83
Existing Investment	Distribution Pipe	HAMI: Haldimand Rd 55, Walpole BU Repl	48977	Value Driven	-	-	6	(166)	172	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.43	0.00	0.00	1.14	3.14	0.00	0.00	0.00	0.00	0.00	39.06	114.31	2.62
No Longer in Plan	Distribution Pipe	HAMI: Rifle Range Rd, Hamilton, BU Replacement	733645	Value Driven	-	-	4	(181)	186	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.35	0.00	0.00	1.24	3.40	0.00	0.00	0.00	0.00	0.00	42.20	123.51	2.83
Emergent	Distribution Pipe	SARN - London Rd Leakage BU Remainder- Sarnia	739402	Mandatory	$ 733,993	-	(550)	(550)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	BRAN - Schafer Side Rd. Repl. BU - Norfolk	48928	Value Driven	-	-	(474)	(572)	99	0.00	0.83	0.00	0.00	3.34	3.50	0.00	0.00	0.00	0.00	8.10	30.79	0.00	0.00	0.00	0.00	0.00	39.06	11.43	1.82
No Longer in Plan	Distribution Pipe	WIND: Bayshore Dr, Leamington, Replacement	102255	Value Driven	-	-	392	(120)	512	0.00	56.53	0.00	0.00	0.00	238.44	0.00	12.35	0.00	0.00	0.04	36.23	0.00	0.00	0.00	0.00	0.00	42.20	123.51	2.83
Existing Investment	Distribution Pipe	SARN - Errol Rd W & Newell St. Leakage - Sarnia BU	48951	Value Driven	-	-	(401)	(596)	195	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.43	0.00	0.00	0.04	60.97	0.00	0.00	0.00	0.00	0.00	1.71	114.31	6.29
Existing Investment	Distribution Pipe	LOND - Dalmage & Wood BU - London	48829	Value Driven	-	-	45	(106)	151	0.00	3.38	0.00	0.00	10.09	14.27	0.00	10.58	0.00	0.00	0.04	2.91	0.00	0.00	0.00	0.00	0.00	1.59	105.80	2.42
Existing Investment	Distribution Pipe	HAMI: Seneca Dr, Ancaster, BU Replacement	733642	Value Driven	-	-	32	(140)	172	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.43	0.00	0.00	1.14	3.14	0.00	0.00	0.00	0.00	0.00	39.06	114.31	2.62
No Longer in Plan	Distribution Pipe	HAMI: Hamilton Mountain East Ph1, Hamilton, BU Replacement	48953	Value Driven	-	-	75	(111)	186	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.35	0.00	0.00	1.24	3.40	0.00	0.00	0.00	0.00	0.00	42.20	123.51	2.83
Existing Investment	Distribution Pipe	LOND-Sycamore & St Julien - London	48828	Value Driven	-	-	414	(110)	524	0.00	19.37	0.00	0.00	301.20	81.71	0.00	10.58	0.00	0.00	0.04	2.91	0.00	0.00	0.00	0.00	0.00	0.31	105.80	2.42
No Longer in Plan	Distribution Pipe	HAMI - Main at Leland - Hamilton	48985	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	LOND - Waterloo St. BU - London	48372	Value Driven	$ 1,640,816	-	(526)	(854)	329	0.00	15.80	0.00	0.00	0.47	66.64	0.00	14.42	0.00	0.00	0.05	76.89	0.00	0.00	0.00	0.00	0.00	2.16	144.17	7.93
Existing Investment	Distribution Pipe	LOND - Waterloo St at Horton St Leakage BU- London	733531	Value Driven	-	$ 417,736	(68)	(296)	227	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.34	0.00	0.00	0.04	71.17	0.00	0.00	0.00	0.00	0.00	2.00	133.45	7.34
Existing Investment	Distribution Pipe	Moulton Replacement BU	503350	Value Driven	-	$ 757,797	(11,735)	(11,921)	186	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.35	0.00	0.00	1.24	3.40	0.00	0.00	0.00	0.00	0.00	42.20	123.51	2.83
No Longer in Plan	Distribution Pipe	LOND - Elworthy & Edward BU - London	48874	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	HAMI-Haldimand Trail - Dunn	48788	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	HAMI: Port Maitland/Secord Rd, Dunnville, BU Repl	733632	Value Driven	-	-	238	(72)	309	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.35	0.00	0.00	1.24	3.40	0.00	0.00	0.00	0.00	0.00	42.20	247.02	2.83
Existing Investment	Distribution Pipe	LOND - Tecumseh Ave BU - London	48923	Value Driven	-	-	51	(215)	266	0.00	13.54	0.00	0.00	0.40	57.09	0.00	11.43	0.00	0.00	0.04	60.97	0.00	0.00	0.00	0.00	0.00	1.71	114.31	6.29
Existing Investment	Distribution Pipe	SARN- Brigden Rd and Duncan St Leakage - Moore Twp	502679	Value Driven	-	-	230	(77)	307	0.00	12.69	0.00	81.32	0.09	53.52	0.00	10.58	0.00	0.00	1.06	2.91	0.00	0.00	0.00	0.00	0.00	36.15	105.80	2.42
No Longer in Plan	Distribution Pipe	HAMI: Rymer Rd, Sherbrooke, BU Replacement	733628	Value Driven	-	-	224	(85)	309	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.35	0.00	0.00	1.24	3.40	0.00	0.00	0.00	0.00	0.00	42.20	247.02	2.83
Existing Investment	Distribution Pipe	HAMI: Main St E, Dunnville, BU Replacement	733621	Value Driven	-	-	6	(280)	286	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.43	0.00	0.00	1.14	3.14	0.00	0.00	0.00	0.00	0.00	39.06	228.63	2.62
Existing Investment	Distribution Pipe	HAMI: Haldimand Rd 20, Walpole, BU Replacement	733626	Value Driven	-	-	175	(79)	254	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	1.06	2.91	0.00	0.00	0.00	0.00	0.00	36.15	211.59	2.42
Existing Investment	Distribution Pipe	BRAN -Northern Ave. (Adams to Connaught) Repl. BU - Delhi	48955	Value Driven	-	-	(263)	(464)	201	0.00	0.83	0.00	0.00	0.06	3.50	0.00	0.00	0.00	0.00	8.14	33.53	0.00	0.00	0.00	0.00	0.00	39.06	114.31	1.90
Existing Investment	Distribution Pipe	HAMI: Rainham Rd Ph2, Dunn, BU Replacement	733623	Value Driven	-	-	(671)	(843)	172	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.43	0.00	0.00	1.14	3.14	0.00	0.00	0.00	0.00	0.00	39.06	114.31	2.62
No Longer in Plan	Distribution Pipe	HAMI: Rainham Rd Ph1, Dunn, BU Replacement	733622	Value Driven	-	-	(788)	(974)	186	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.35	0.00	0.00	1.24	3.40	0.00	0.00	0.00	0.00	0.00	42.20	123.51	2.83
Existing Investment	Distribution Pipe	HAMI: Rainham Road, Walpole BU Repl	48954	Value Driven	-	-	(302)	(461)	159	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.58	0.00	0.00	1.06	2.91	0.00	0.00	0.00	0.00	0.00	36.15	105.80	2.42
No Longer in Plan	Distribution Pipe	WATE - Glen Morris (Selkirk to Stanley) Repl. BU - Cambridge	48937	Value Driven	-	-	(25)	(243)	218	0.00	0.90	0.00	0.00	0.07	3.78	0.00	0.00	0.00	0.00	8.79	36.23	0.00	0.00	0.00	0.00	0.00	42.20	123.51	2.05
No Longer in Plan	Distribution Pipe	WATE - Hamilton St. Repl. BU - Cambridge	48936	Value Driven	-	-	(276)	(412)	136	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.92	6.59	0.00	0.00	0.00	0.00	0.00	4.22	123.51	0.29
No Longer in Plan	Distribution Pipe	LOND - Jacqueline BU - London	48811	Value Driven	-	-	(839)	(1,126)	287	0.00	14.62	0.00	0.00	0.43	61.68	0.00	12.35	0.00	0.00	0.04	65.87	0.00	0.00	0.00	0.00	0.00	1.85	123.51	6.79

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
Existing Investment	Distribution Pipe	LOND - Church & Water BU - Beachville	48808	Value Driven	-	-	171	(74)	244	0.00	16.92	0.00	0.00	34.08	71.36	0.00	10.58	0.00	0.00	0.04	2.91	0.00	0.00	0.00	0.00	0.00	0.31	105.80	2.42
Existing Investment	Distribution Pipe	LOND - Kent & Central BU - London	48797	Value Driven	-	-	18	(153)	171	0.00	5.81	0.00	0.00	1.25	24.51	0.00	10.58	0.00	0.00	0.04	3.70	0.00	0.00	0.00	0.00	0.00	1.59	105.80	17.50
Existing Investment	Distribution Pipe	BRAN - Otterville Rd. (James to Middleton) Repl. BU - Otterville	48849	Value Driven	-	-	(331)	(517)	186	0.00	0.71	0.00	0.00	0.05	3.00	0.00	0.00	0.00	0.00	7.53	31.03	0.00	0.00	0.00	0.00	0.00	36.15	105.80	1.76
No Longer in Plan	Distribution Pipe	LOND - Cheapside, Gammage & Linwood BU - London	48917	Value Driven	-	-	(899)	(1,085)	186	0.00	3.66	0.00	0.00	10.90	15.42	0.00	13.34	0.00	0.00	0.04	3.67	0.00	0.00	0.00	0.00	0.00	2.00	133.45	3.06
Existing Investment	Distribution Pipe	LOND - Fellner & Langmuir, Ashland & Wilton BU - London	48891	Value Driven	$ 38,674	$ 1,381,276	(1,461)	(1,633)	172	0.00	3.38	0.00	0.00	10.09	14.27	0.00	12.35	0.00	0.00	0.04	3.40	0.00	0.00	0.00	0.00	0.00	1.85	123.51	2.83
Existing Investment	Distribution Pipe	BRAN - Churchill (Connaught to Argyle) Repl. BU - Delhi	48958	Value Driven	-	-	124	(77)	201	0.00	0.83	0.00	0.00	0.07	3.50	0.00	0.00	0.00	0.00	8.14	33.53	0.00	0.00	0.00	0.00	0.00	39.06	114.31	1.90
No Longer in Plan	Distribution Pipe	Halt: Harrop drive, Milton, BU Replacement	503061	Value Driven	-	-	7	(179)	186	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.35	0.00	0.00	1.24	3.40	0.00	0.00	0.00	0.00	0.00	42.20	123.51	2.83
Existing Investment	Distribution Pipe	SARN - Errol Rd E Leakage - Sarnia BU	48846	Value Driven	-	$ 2,167,797	(1,307)	(1,535)	227	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.34	0.00	0.00	0.04	71.17	0.00	0.00	0.00	0.00	0.00	2.00	133.45	7.34
Existing Investment	Distribution Pipe	LOND - Talbot Line BU - Talbotville	48759	Value Driven	-	-	47	(124)	171	0.00	5.81	0.00	0.00	1.25	24.51	0.00	10.58	0.00	0.00	0.04	3.70	0.00	0.00	0.00	0.00	0.00	1.59	105.80	17.50
Existing Investment	Distribution Pipe	SARN-Point Edward LP Leakage - Sarnia BU	48831	Value Driven	$ 39,632	$ 2,032,570	(1,322)	(1,497)	176	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.34	0.00	0.00	0.04	4.67	0.00	0.00	0.00	0.00	0.00	2.00	133.45	22.07
Existing Investment	Distribution Pipe	SARN - Highway Dr and Lynwood Ave - Sarnia BU	48771	Value Driven	-	-	(176)	(298)	122	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.58	0.00	0.00	0.04	2.91	0.00	0.00	0.00	0.00	0.00	0.31	105.80	2.42
No Longer in Plan	Distribution Pipe	LOND - Belgrave BU - London	48765	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	HAMI:Upper Gage Ave, Hamilton, BU Replacement	733654	Value Driven	-	-	(386)	(545)	159	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.58	0.00	0.00	1.06	2.91	0.00	0.00	0.00	0.00	0.00	36.15	105.80	2.42
No Longer in Plan	Distribution Pipe	LOND - Parkway & Huron BU - London	48888	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	HAMI: Sandusk Rd, Walpole BU Repl -PROJECT CANCELLED	48912	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	LOND - PH 2 Stevenson & Brydges BU - London	48856	Value Driven	-	-	(1,320)	(1,481)	161	0.00	3.38	0.00	0.00	10.09	14.27	0.00	11.43	0.00	0.00	0.04	3.14	0.00	0.00	0.00	0.00	0.00	1.71	114.31	2.62
No Longer in Plan	Distribution Pipe	HAMI: South Coast Dr, Walpole BU Repl	48910	Value Driven	-	-	226	(83)	309	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.35	0.00	0.00	1.24	3.40	0.00	0.00	0.00	0.00	0.00	42.20	247.02	2.83
Existing Investment	Distribution Pipe	LOND - Riverside Dr & Wharncliffe BU - London	48881	Value Driven	-	-	446	(78)	524	0.00	19.37	0.00	0.00	301.20	81.71	0.00	10.58	0.00	0.00	0.04	2.91	0.00	0.00	0.00	0.00	0.00	0.31	105.80	2.42
No Longer in Plan	Distribution Pipe	BRAN - Water St. and Rebecca St. Repl. BU - Vittoria	48933	Value Driven	-	-	(67)	(203)	136	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.92	6.59	0.00	0.00	0.00	0.00	0.00	4.22	123.51	0.29
Emergent	Distribution Pipe	BRAN- Spalding Drive Leak Repair, Brantford	739811	Value Driven	$ 358,050	-	(69)	(69)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	SUDB: Bancroft Dr and Bellevue Ave, Valves Replacement	734593	Value Driven	-	-	147	(260)	407	0.00	9.14	0.00	0.00	0.00	38.55	0.00	0.16	0.00	0.00	0.00	4.32	0.00	0.00	0.00	0.00	0.00	3.60	0.00	350.94
Emergent	Distribution Pipe	33-22-619 TBAY - Balsam St - NPS8 Main Repl - Thunder Bay	739469	Value Driven	-	$ 145,870	(103)	(103)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	33-23-609 TBAY - Nelson Rd - 2 PE Main Repl - Shuniah	740698	Value Driven	$ 4,905	-	(4)	(4)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	THUN: PSLL Maintenance	501009	Value Driven	$ 14,887	-	(6)	(6)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	TBAY: 33-23-600 Ackland's / Dryden GM Main & Customer Station	502825	Mandatory	$ -	$ -	(78)	(78)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Darlington Bay Bridge - NPS 2 Replacement	49510	Value Driven	-	-	(388)	(710)	321	0.00	0.00	0.00	0.00	102.93	0.00	0.00	0.00	0.00	0.00	0.00	56.42	0.00	0.00	0.00	0.00	0.00	158.70	0.00	3.30
Emergent	Distribution Pipe	45-23-603 TIMM - Earl St - NPS2 Leak Repair - K Lake	740635	Value Driven	$ 118,259	-	(88)	(88)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Atikokan Steep Rock Mine Valve Nest Retirement	49509	Value Driven	-	-	(52)	(52)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	NW_Lateral Clamp Cut Outs_ATIKOKAN	49256	Value Driven	-	-	(621)	(1,148)	527	0.00	21.99	0.00	180.22	0.00	92.76	0.00	0.01	0.00	0.00	0.00	227.59	0.00	0.00	0.00	0.00	0.00	2.26	0.00	1.85
Emergent	Distribution Pipe	King: 22-23-604 Pelham Street Abandonment	740592	Value Driven	$ 12,010	-	(4)	(4)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	King - Lowering on Water Street (Napanee)	100750	Value Driven	-	-	(26)	(26)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	King: 22-23-600 Collins Bay NPS10 Shallow Pipe	100744	Value Driven	$ 128,913	$ 1,256,680	4,330	(986)	5,317	0.00	10.18	0.00	0.00	0.00	42.93	0.00	13.35	0.00	0.00	0.04	359.41	0.00	0.00	0.00	0.00	0.00	4,781.80	13.35	95.47
Existing Investment	Distribution Pipe	NBAY: 247 Whitewood Ave, New Liskeard Main Relocation	49625	Value Driven	-	-	(4)	(78)	75	0.00	0.00	0.00	0.00	64.66	0.00	0.00	7.76	0.00	0.00	0.00	2.09	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.14
Emergent	Distribution Pipe	King: 22-23-630 Mill & Water - Gen. Rep. for Backyard Service	738478	Mandatory	$ 49,731	-	(51)	(51)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	King - King Street Replacement: VSM and Patches (Prescott)	100693	Value Driven	-	-	877	(792)	1,669	0.00	0.00	0.00	1,543.89	102.93	0.00	0.00	9.06	0.00	0.00	0.09	2.66	0.00	0.00	0.00	0.00	0.00	0.31	9.06	0.79
Existing Investment	Distribution Pipe	King: Thin Wall and Copper Pipe Replacement (Various Locations in Area	734706	Value Driven	-	-	(258)	(258)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	King: 22-23-602 Murney & Catherine Leak Repair (Belleville)	739846	Value Driven	$ 6,738	-	(17)	(17)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	LOND - Trafalgar & Oliver Leakage - London	738868	Value Driven	$ 202,048	-	(128)	(128)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	TBAY: 33-22-601 Atikokan Lateral Leak Dwnst of Sapawe Mill	503015	Value Driven	$ 1,905,355	-	(1,438)	(1,438)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	WIND: PSLL Maintenance	501004	Value Driven	$ 194,220	$ 846,207	(989)	(989)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	NE: Hwy 11 and Barnett, North Bay, Grasshopper Valves Replacement	735150	Value Driven	-	-	236	(222)	457	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	227.59	0.00	0.00	0.00	0.00	0.00	226.30	0.00	3.43
Existing Investment	Distribution Pipe	HAMI: 295 Dundas St E 6" ST IP Shallow Main Waterdown	100843	Value Driven	-	-	80	(79)	159	0.00	18.28	0.00	36.04	0.00	77.10	0.00	0.00	0.00	0.00	0.00	26.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.55
Existing Investment	Distribution Pipe	HAMI: Crestview Replacement, Ancaster, Leakage	101631	Value Driven	-	$ 1,361,193	129	(964)	1,093	0.00	9.14	0.00	72.09	0.00	38.55	0.00	0.00	0.00	0.00	0.04	4.67	0.00	0.00	0.00	0.00	0.00	455.94	133.45	379.04
Emergent	Distribution Pipe	HAMI: Jackson St Valve Replacement, Hamilton, Replacement	738878	Value Driven	-	$ 24,908	(18)	(18)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	2023 LLRP - Dawn South Yard Control Valve Installation	740575	Value Driven	$ 275,898	-	8,245	(317)	8,562	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.13	0.00	0.00	0.00	2,834.01	0.00	0.00	0.00	0.00	0.00	5,475.88	171.57	21.11
Existing Investment	Distribution Pipe	King: Bath and Gardiners Valve Replacement (Kingston)	734743	Value Driven	-	-	(115)	(115)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	King: Fifth & McConnell Concrete Encased Main Replacement (Cornwall	734741	Value Driven	-	-	(56)	(56)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	King: 22-23-603 Dundas Street Leak Replacement (Belleville)	740016	Value Driven	$ 52,237	-	(17)	(17)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	LOND - SCLAIR Pipe Replacement- Mount Brydges	101543	Value Driven	-	-	(392)	(404)	11	0.00	1.15	0.00	0.00	0.00	4.85	0.00	0.00	0.00	0.00	0.00	2.26	0.00	0.00	0.00	0.00	0.00	2.86	0.00	0.13
Existing Investment	Distribution Pipe	LOND - 7113 to 7079 Longwoods Rd. - London	734459	Value Driven	-	-	(14)	(111)	97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.38	0.00	0.00	0.03	2.31	0.00	0.00	0.00	0.00	0.00	0.03	83.85	1.92
Existing Investment	Distribution Pipe	LOND - Breck Ave. & Eastgate Cres. - London	734460	Value Driven	-	-	(80)	(104)	24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.03	0.02	23.82
Existing Investment	Distribution Pipe	TIMM: Xstrata (Kidd Creek) Smelter SMS Service Retirement & 8" Latera	100951	Value Driven	$ 1,588,651	-	(1,190)	(1,190)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	WATE Atwood Station Inlet Obstruction Emergency Cut Out General Re	739834	Value Driven	$ 135,245	-	(123)	(123)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	NE: Ski Club Rd., North Bay	102476	Value Driven	-	-	(208)	(210)	3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.46	0.00	0.00	0.00	0.00	0.00	0.29	0.00	0.01
Emergent	Distribution Pipe	BRAN- Windham Center Leak Repair. Windham	738968	Value Driven	$ 285,171	-	(219)	(219)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	HAMI: Jackson Street Leakage, Hamilton, Leakage	100924	Value Driven	-	-	471	(832)	1,303	0.00	0.00	0.00	88.96	111.20	0.00	0.00	0.00	0.00	0.00	0.00	362.30	0.00	0.00	0.00	0.00	0.00	617.56	0.00	122.48
No Longer in Plan	Distribution Pipe	WIND: Tecumseh Rd E - Ph4, Windsor, Replacement	101175	Value Driven	-	-	3,453	(745)	4,198	0.00	475.22	0.00	700.92	0.00	2,004.36	0.00	12.35	0.00	0.00	0.04	362.30	0.00	0.00	0.00	0.00	0.00	360.24	247.02	35.87
Existing Investment	Distribution Pipe	WIND: Tecumseh Rd E - Ph6, Windsor, Replacement	101177	Value Driven	-	$ 1,136,696	3,476	(805)	4,280	0.00	475.22	0.00	700.92	0.00	2,004.36	0.00	13.34	0.00	0.00	0.04	391.44	0.00	0.00	0.00	0.00	0.00	389.22	266.89	38.75
Existing Investment	Distribution Pipe	WIND: County Rd 2 & Riverside Rd, Lakeshore, Replacement	48865	Value Driven	-	-	1,240	(128)	1,369	0.00	28.99	0.00	57.16	0.05	122.26	0.00	0.00	0.00	0.00	0.35	56.42	0.00	0.00	0.00	0.00	0.00	36.15	1,057.97	9.17
Existing Investment	Distribution Pipe	WIND: County Rd 31 & Essex County Rd 2, Lakeshore, Replacement	48851	Value Driven	-	-	882	(487)	1,369	0.00	28.99	0.00	57.16	0.05	122.26	0.00	0.00	0.00	0.00	0.35	56.42	0.00	0.00	0.00	0.00	0.00	36.15	1,057.97	9.17
Existing Investment	Distribution Pipe	WIND: Glenwood Line & Port Rd, Chatham-Kent, Replacement	49734	Value Driven	-	-	(151)	(183)	32	0.00	1.22	0.00	20.96	0.00	5.13	0.00	0.00	0.00	0.00	0.00	4.14	0.00	0.00	0.00	0.00	0.00	0.27	0.00	0.01
Emergent	Distribution Pipe	Mill Creek Cres Replacement	49739	Value Driven	-	-	(26)	(26)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	WIND: Riverside Aldyl A - Ph 1, Windsor, Replacement	49743	Value Driven	-	-	1,452	(1,108)	2,560	0.00	13.41	0.00	0.00	0.00	56.58	0.00	1,057.98	0.00	0.00	0.00	56.42	0.00	0.00	0.00	0.00	0.00	308.57	1,057.97	9.17
Existing Investment	Distribution Pipe	WIND: County Rd 27 Ph 3, Lakeshore, Replacement	49746	Value Driven	-	-	1,080	(245)	1,325	0.00	22.98	0.00	45.30	0.04	96.91	0.00	0.00	0.00	0.00	0.35	56.42	0.00	0.00	0.00	0.00	0.00	36.15	1,057.97	9.17
Existing Investment	Distribution Pipe	WIND: Tecumseh Rd W, Windsor, Replacement	49747	Value Driven	-	-	1,679	(1,289)	2,967	0.00	322.78	0.00	476.09	0.00	1,361.41	0.00	9.79	0.00	0.00	0.03	287.21	0.00	0.00	0.00	0.00	0.00	285.57	195.82	28.43
Existing Investment	Distribution Pipe	WIND: Trenton St, Windsor, Replacement	49750	Value Driven	-	-	(159)	(185)	26	0.00	0.00	0.00	18.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.14	0.00	0.00	0.00	0.00	0.00	3.88	0.00	0.07
Existing Investment	Distribution Pipe	WIND: Tecumseh Rd E - Ph3, Windsor, Replacement	49752	Value Driven	-	-	2,964	(430)	3,394	0.00	376.82	0.00	555.80	0.00	1,589.37	0.00	10.58	0.00	0.00	0.04	310.34	0.00	0.00	0.00	0.00	0.00	308.57	211.59	30.73
Existing Investment	Distribution Pipe	WIND: County Rd 27 Ph 1, Lakeshore, Replacement	48796	Value Driven	-	-	537	(730)	1,267	0.00	26.83	0.00	52.90	0.04	113.15	0.00	0.00	0.00	0.00	0.33	52.22	0.00	0.00	0.00	0.00	0.00	33.45	979.11	8.49
Existing Investment	Distribution Pipe	WIND: Laird IP, Essex, Replacement	48781	Value Driven	-	-	900	(469)	1,369	0.00	28.99	0.00	57.16	0.05	122.26	0.00	0.00	0.00	0.00	0.35	56.42	0.00	0.00	0.00	0.00	0.00	36.15	1,057.97	9.17
Existing Investment	Distribution Pipe	WIND: Maidstone Ave & Talbot St, Essex, Replacement	48779	Value Driven	-	-	1,196	(142)	1,339	0.00	24.83	0.00	48.96	0.04	104.72	0.00	0.00	0.00	0.00	0.35	56.42	0.00	0.00	0.00	0.00	0.00	36.15	1,057.97	9.17
No Longer in Plan	Distribution Pipe	WIND: Riverside Dr (Arlington to Kensington), Windsor, Replacement	48762	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	SUDB: Regent St grasshopper, Sudbury	49653	Value Driven	-	-	335	(143)	478	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	227.59	0.00	0.00	0.00	0.00	0.00	226.30	0.00	24.18
Existing Investment	Distribution Pipe	WIND: Oak St - Ph 2, Leamington, Replacement	49812	Value Driven	-	-	(218)	(848)	630	0.00	69.11	0.00	0.00	0.00	291.49	0.00	0.00	0.00	0.00	0.00	225.83	0.00	0.00	0.00	0.00	0.00	41.92	0.00	1.57
Existing Investment	Distribution Pipe	WIND: Tecumseh Rd E - Ph 2, Windsor, Replacement	49814	Value Driven	-	-	1,705	(1,436)	3,141	0.00	348.76	0.00	514.41	0.00	1,471.00	0.00	9.79	0.00	0.00	0.03	287.21	0.00	0.00	0.00	0.00	0.00	285.57	195.82	28.43
No Longer in Plan	Distribution Pipe	SUDB: Copper Cliff Replacement	735465	Value Driven	-	-	(635)	(1,011)	376	0.00	9.14	0.00	0.00	0.00	38.55	0.00	123.51	0.00	0.00	0.00	36.23	0.00	0.00	0.00	0.00	0.00	42.20	123.51	2.83
Existing Investment	Distribution Pipe	SUDB: Gagnon St Lateral, Azilda	49641	Value Driven	-	-	(78)	(78)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	SSM: Goulais Rd Main replacement SSM	49628	Value Driven	-	-	(68)	(550)	482	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	227.59	0.00	0.00	0.00	0.00	0.00	226.30	0.00	28.19
Existing Investment	Distribution Pipe	WIND: Mersea Rd 2 - Ph 2, Leamington, Replacement	49816	Value Driven	-	$ 2,210,241	(595)	(1,544)	950	0.00	99.83	0.00	0.00	0.00	421.08	0.00	0.00	0.00	0.00	0.00	359.41	0.00	0.00	0.00	0.00	0.00	66.72	0.00	2.49
Emergent	Distribution Pipe	01-23-610 WIND Bubbling Pipe Cut Outs	740674	Mandatory	$ 32,228	-	(46)	(46)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Bush Line Leakage Replacement Phase 1 & 2	49714	Value Driven	-	-	(683)	(683)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	WIND: Bertha Ave, Windsor, Replacement	49722	Value Driven	-	-	1,015	(298)	1,313	0.00	21.26	0.00	41.92	0.03	89.68	0.00	0.00	0.00	0.00	0.35	56.42	0.00	0.00	0.00	0.00	0.00	36.15	1,057.97	9.17
Emergent	Distribution Pipe	Dawn Mills Bare Steel Replacement	49728	Mandatory	-	-	(239)	(239)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	WIND: Caille Ave, Lakeshore, VSM Replacement	49889	Value Driven	$ 7,303	-	570	(743)	1,313	0.00	21.26	0.00	41.92	0.03	89.68	0.00	0.00	0.00	0.00	0.35	56.42	0.00	0.00	0.00	0.00	0.00	36.15	1,057.97	9.17
Existing Investment	Distribution Pipe	Fairview Line Replacement	49732	Value Driven	-	-	(482)	(482)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	WIND: 40 Cameron Rd W Leak Repair, Kingsville, Replacement	739933	Mandatory	$ 143,966	-	(62)	(62)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	CHAT: Water St & Talbot Trail, Chatham-Kent, Replacement	49893	Value Driven	-	-	(75)	(106)	32	0.00	1.22	0.00	20.96	0.00	5.13	0.00	0.00	0.00	0.00	0.00	4.14	0.00	0.00	0.00	0.00	0.00	0.27	0.00	0.01
Existing Investment	Distribution Pipe	SUDB: RR 15 Property Line, Chelmsford, Replacement	734812	Value Driven	-	-	(187)	(1,065)	878	0.00	54.84	0.00	0.00	0.00	231.30	0.00	105.80	0.00	0.00	0.00	1.16	0.00	0.00	0.00	0.00	0.00	361.47	105.80	17.50
Existing Investment	Distribution Pipe	CHAT: St Clair St, Tilbury, Replacement	49856	Value Driven	-	-	1,446	(300)	1,746	0.00	22.98	0.00	45.30	0.04	96.91	0.00	0.00	0.00	0.00	0.48	76.89	0.00	0.00	0.00	0.00	0.00	49.26	1,441.74	12.50
Existing Investment	Distribution Pipe	Tilbury South Line Replacement	49749	Value Driven	-	-	(1,073)	(1,073)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	CHAT: Base Line, Wallaceburg, Replacement	49721	Value Driven	-	$ 12,630	(436)	(713)	277	0.00	0.00	0.00	100.08	0.25	0.00	0.00	0.00	0.00	0.00	0.00	65.87	0.00	0.00	0.00	0.00	0.00	61.76	0.36	48.38
Emergent	Distribution Pipe	SARN- Petrolia Line and Telfer Rd Replacement- St Clair	739237	Mandatory	-	$ 353,639	(250)	(250)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	SARN - Vidal St Walking Bridge Valve Install - Sarnia	739194	Mandatory	-	-	(152)	(152)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	SARN - Oil Heritage Rd and Douglas Line Exposed Main	733836	Value Driven	-	$ 176,819	(124)	(125)	1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.24	0.01	0.00	0.00	0.00	0.00	0.00	0.67	0.00	0.00
Emergent	Distribution Pipe	SARN- 2905 Bentpath Line Replacement - Sombra	738109	Mandatory	$ 348,064	-	(217)	(217)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	LOND- 1640 Mandaumin Rd Aerial Crossing- Dawn	739576	Mandatory	$ 386,251	-	(362)	(362)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	SARN Oil Springs Line (Sarnia 10) Aerial Crossing Replacement- St Clair	740848	Mandatory	-	$ 315,749	(224)	(224)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	WIND: Lacasse (St Denis to Tecumseh Rd E), Windsor, Replacement	48782	Value Driven	-	-	1,411	(228)	1,638	0.00	39.50	0.00	77.88	0.06	166.59	0.00	0.00	0.00	0.00	0.41	65.87	0.00	0.00	0.00	0.00	0.00	42.20	1,235.12	10.70
Emergent	Distribution Pipe	Partington Ave - Southwest - Windsor - 1293	30030	Value Driven	-	-	(744)	(784)	39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.23	0.00	0.00	0.00	0.19	0.00	0.00	3.33	0.48
Emergent	Distribution Pipe	Div. 16 - Hamilton - Market St - Hamilton - 1456	30408	Value Driven	-	-	(1,268)	(1,348)	80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.31	0.00	0.00	0.00	1.49	0.00	0.00	4.78	0.62

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
Existing Investment	Distribution Pipe	Barton St - Southwest - Windsor - 1657	30029	Value Driven	-	-	(524)	(539)	15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.59	0.00	0.00	0.00	0.02	0.00	0.00	1.50	0.22
Existing Investment	Distribution Pipe	Presley St 2 - Northeast - 1714	30229	Value Driven	-	-	(796)	(829)	34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.85	0.00	0.00	0.00	0.05	0.00	0.00	2.54	0.37
Existing Investment	Distribution Pipe	Seventh St S-Kenora-1542	30158	Value Driven	-	-	(1,352)	(1,402)	50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	45.33	0.00	0.00	0.00	0.14	0.00	0.00	3.91	0.55
Existing Investment	Distribution Pipe	Kenora- Seventh Ave N-Phase 1 VSM Replacement	30157	Value Driven	-	-	(1,541)	(1,621)	80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	72.10	0.00	0.00	0.00	0.83	0.00	0.00	5.98	0.85
Existing Investment	Distribution Pipe	Ogden St-Thunder Bay-1568	30155	Value Driven	-	-	(1,845)	(1,897)	52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	47.31	0.00	0.00	0.00	0.14	0.00	0.00	3.99	0.59
Existing Investment	Distribution Pipe	Ontario Rd - Southwest - London - 1803	30465	Value Driven	-	-	(442)	(470)	28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.87	0.00	0.00	0.00	0.07	0.00	0.00	1.94	0.30
Emergent	Distribution Pipe	OBrien Ave Ph 1-Kapuskasing-1856	30154	Value Driven	-	-	(721)	(788)	67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.79	0.00	0.00	0.00	0.79	0.00	0.00	3.99	0.55
Existing Investment	Distribution Pipe	Queen St E - Southwest - London - 1804	30466	Value Driven	-	-	(748)	(809)	61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.77	0.00	0.00	0.00	0.44	0.00	0.00	3.34	0.55
Emergent	Distribution Pipe	Grand River St S - Southeast - Waterloo - 1805	30469	Value Driven	-	-	(394)	(394)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	WATE: Carden St, Guelph, VSM Replacement	30468	Value Driven	-	$ 31,575	(1,423)	(1,423)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Arthur St N - Southeast - Waterloo - 1800	30467	Value Driven	-	-	(620)	(620)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Distribution Pipe	Princess St W 1 (MORATORIUM UNTIL 2026) - Northeast - 1721	30230	Value Driven	-	-	(371)	(391)	20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.40	0.00	0.00	0.00	0.29	0.00	0.00	1.28	0.17
Existing Investment	Distribution Pipe	Marks St S-Thunder Bay-1537	30151	Value Driven	-	-	(2,221)	(2,310)	89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	78.75	0.00	0.00	0.00	3.89	0.00	0.00	5.60	0.74
Existing Investment	Distribution Pipe	Div. 16 - Haldimand - Fisherville - Erie Ave N 2 - Hamilton - 1730	30400	Value Driven	-	-	(419)	(691)	272	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	249.40	0.00	0.00	0.00	0.06	0.00	0.00	19.31	2.79
Existing Investment	Distribution Pipe	Hart St-Timmins (MORATORIUM UNTIL 2025) -1559	30146	Value Driven	-	-	(1,724)	(1,763)	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.81	0.00	0.00	0.00	0.14	0.00	0.00	3.01	0.43
Existing Investment	Distribution Pipe	Cheapside St 2 - Southwest - London -1534	30283	Value Driven	-	-	(1,630)	(1,867)	237	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	224.45	0.00	0.00	0.00	2.11	0.00	0.00	9.34	1.34
Emergent	Distribution Pipe	Stratford-Grange St - Waterloo to Front-1774	30459	Value Driven	-	-	(280)	(287)	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.15	0.00	0.00	0.00	0.02	0.00	0.00	0.53	0.08
Existing Investment	Distribution Pipe	George St-Hearst-1558	30145	Value Driven	-	-	(1,882)	(1,934)	52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	47.59	0.00	0.00	0.00	0.20	0.00	0.00	3.83	0.57
Existing Investment	Distribution Pipe	Finlayson St-Thunder Bay-1870	30144	Value Driven	-	-	(1,132)	(1,168)	36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.39	0.00	0.00	0.00	0.06	0.00	0.00	3.11	0.44
Emergent	Distribution Pipe	Stratford-Cobourg St - Parkview to Queen-1773	30458	Value Driven	-	-	(192)	(204)	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.21	0.00	0.00	0.00	0.01	0.00	0.00	0.90	0.13
Existing Investment	Distribution Pipe	Dominion Ave-Kapuskasing-1499	30143	Value Driven	-	-	(1,677)	(1,738)	61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.79	0.00	0.00	0.00	0.14	0.00	0.00	4.65	0.67
Existing Investment	Distribution Pipe	Dominion Ave 2-Kapuskasing-1540	30142	Value Driven	-	-	(887)	(925)	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.03	0.00	0.00	0.00	0.06	0.00	0.00	2.87	0.41
Emergent	Distribution Pipe	Circle St 1-Kapuskasing-1847	30140	Value Driven	-	-	(694)	(719)	25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.66	0.00	0.00	0.00	0.05	0.00	0.00	1.99	0.28
Emergent	Distribution Pipe	Div. 16 - Haldimand - Jarvis - Talbot St E - Hamilton - 1732	30401	Value Driven	-	-	(967)	(1,406)	439	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	408.44	0.00	0.00	0.00	1.33	0.00	0.00	25.61	4.08
Emergent	Distribution Pipe	Morand St - Southwest - Windsor - 1656	30028	Value Driven	-	-	(855)	(963)	108	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	96.88	0.00	0.00	0.00	0.23	0.00	0.00	9.46	1.36
Existing Investment	Distribution Pipe	Sixth Ave-Timmins-1566	30159	Value Driven	-	-	(1,440)	(1,487)	47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.79	0.00	0.00	0.00	0.87	0.00	0.00	3.47	0.46
Emergent	Distribution Pipe	Byng Ave 1-Kapuskasing-1850	30139	Value Driven	-	-	(714)	(752)	39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.11	0.00	0.00	0.00	0.07	0.00	0.00	3.19	0.43
Existing Investment	Distribution Pipe	Bay St-Timmins-1561	30137	Value Driven	-	-	(1,792)	(1,849)	58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.21	0.00	0.00	0.00	0.32	0.00	0.00	3.79	0.55
Emergent	Distribution Pipe	Ann St (MORATORIUM UNTIL 2028) - Southwest - London - 1402	30276	Value Driven	-	-	(1,739)	(1,887)	147	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	134.44	0.00	0.00	0.00	0.16	0.00	0.00	11.15	1.62
Emergent	Distribution Pipe	Birch St N (MORATORIUM UNTIL 2028) -Timmins-1550	30138	Value Driven	-	-	(1,522)	(1,580)	58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.30	0.00	0.00	0.00	0.14	0.00	0.00	4.91	0.64
Emergent	Distribution Pipe	Haldimand - Selkirk - Erie St S-Phase 1 - Hamilton - VSM Replacement	30402	Value Driven	$ 18,919	-	(1,252)	(1,270)	18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.24	0.00	0.00	0.00	0.04	0.00	0.00	1.68	0.24
Emergent	Distribution Pipe	Stratford-Avon St - Avondale to McLagan-1772	30457	Value Driven	-	-	(355)	(368)	13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.01	0.00	0.00	0.00	0.02	0.00	0.00	1.02	0.15
Emergent	Distribution Pipe	Dundas St 2 (MORATORIUM UNTIL 2030) - Southwest - London - 1518	30288	Value Driven	-	-	(960)	(1,087)	128	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	118.23	0.00	0.00	0.00	0.17	0.00	0.00	8.10	1.00
Existing Investment	Distribution Pipe	Elworthy Ave (MORATORIUM UNTIL 2026) - Southwest - London - 1446	30291	Value Driven	-	-	1,813	(2,073)	3,886	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3,565.93	0.00	0.00	0.00	2.32	0.00	0.00	278.47	39.44
Emergent	Distribution Pipe	Stratford-Woods St - Birmingham to St. Vincent-1771	30456	Value Driven	-	-	(240)	(248)	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.56	0.00	0.00	0.00	0.01	0.00	0.00	0.63	0.09
Emergent	Distribution Pipe	Div. 16 - Hamilton - Kenilworth Ave N - Hamilton - 1733	30407	Value Driven	-	-	(1,014)	(1,115)	102	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	92.32	0.00	0.00	0.00	0.09	0.00	0.00	8.07	1.21
Emergent	Distribution Pipe	Div. 07 - Waterloo - Union St E - Southeast - Waterloo - 1390	30274	Value Driven	-	-	(1,718)	(1,774)	57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.19	0.00	0.00	0.00	0.11	0.00	0.00	3.93	0.55
Emergent	Distribution Pipe	Div. 07 - Meaford - Louisa St - Southeast - Waterloo - 1278	30273	Value Driven	-	-	765	(1,185)	1,950	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,753.39	0.00	0.00	0.00	90.99	0.00	0.00	94.16	11.19
Existing Investment	Distribution Pipe	Div. 06 - Tillsonburg - Victoria St - Southeast - Waterloo - 1324	30272	Value Driven	-	-	(809)	(846)	36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.97	0.00	0.00	0.00	0.09	0.00	0.00	2.88	0.41
Existing Investment	Distribution Pipe	Alder St 2 (MORATORIUM UNTIL 2026) - Northeast - 1716	30199	Value Driven	-	-	(698)	(728)	29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.45	0.00	0.00	0.00	0.37	0.00	0.00	2.21	0.27
Existing Investment	Distribution Pipe	Alder St 1 (MORATORIUM UNTIL 2026) - Northeast - 1715	30198	Value Driven	-	-	(760)	(791)	32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.44	0.00	0.00	0.00	1.00	0.00	0.00	1.82	0.25
Existing Investment	Distribution Pipe	Hemlock St-Timmins-1569	30147	Value Driven	-	-	(975)	(1,006)	30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.37	0.00	0.00	0.00	0.12	0.00	0.00	2.35	0.33
Emergent	Distribution Pipe	Div. 06 - Tillsonburg - Tillson Ave - Southeast - Waterloo - 1392	30271	Value Driven	-	-	(1,162)	(1,198)	36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.54	0.00	0.00	0.00	0.13	0.00	0.00	3.89	0.56
Existing Investment	Distribution Pipe	Div. 06 - Tillsonburg - Quarter Town Line - Southeast - Waterloo - 1383	30270	Value Driven	-	-	(1,448)	(1,501)	52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.66	0.00	0.00	0.00	0.36	0.00	0.00	1.75	0.41
Existing Investment	Distribution Pipe	Div. 06 - Tillsonburg - Potters Rd - Southeast - Waterloo - 1375	30269	Value Driven	-	-	(1,188)	(1,237)	48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.16	0.00	0.00	0.00	0.06	0.00	0.00	3.68	0.54
Emergent	Distribution Pipe	Div. 06 - Tillsonburg - Hyman St - Southeast - Waterloo - 1374	30268	Value Driven	-	-	(803)	(914)	112	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	105.02	0.00	0.00	0.00	0.24	0.00	0.00	5.44	0.80
Existing Investment	Distribution Pipe	Div. 06 - Tillsonburg - Brownsville Rd - Southeast - Waterloo - 1391	30267	Value Driven	-	-	(1,118)	(1,134)	16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.18	0.00	0.00	0.00	0.05	0.00	0.00	1.20	0.18
Existing Investment	Distribution Pipe	Div. 06 - Norfolk County - Tillsonburg - 3rd Concession Rd N - Southeast	30266	Value Driven	-	-	(1,328)	(1,423)	95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	87.54	0.00	0.00	0.00	0.34	0.00	0.00	6.24	0.93
Emergent	Distribution Pipe	Div. 06 - Norfolk County - Simcoe - Blue Line Rd - Southeast - Waterloo -	30265	Value Driven	-	-	(1,724)	(1,996)	272	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	257.65	0.00	0.00	0.00	4.44	0.00	0.00	8.86	1.32
Emergent	Distribution Pipe	Div. 06 - Norfolk County - Silver Hill - 10th Concession Rd - Southeast - V	30264	Value Driven	-	-	(727)	(1,169)	442	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	406.05	0.00	0.00	0.00	0.01	0.00	0.00	31.71	4.55
Emergent	Distribution Pipe	Div. 06 - Norfolk County - Halfway House Corner - Vittoria Rd - Southeas	30262	Value Driven	-	-	(907)	(1,149)	242	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	230.48	0.00	0.00	0.00	0.18	0.00	0.00	9.47	1.38
Emergent	Distribution Pipe	Div. 06 - Norfolk County - Atherton - Lynedoch Rd - Southeast - Waterlo	30261	Value Driven	-	-	(314)	(455)	141	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	129.46	0.00	0.00	0.00	0.02	0.00	0.00	9.87	1.46
Emergent	Distribution Pipe	Div. 06 - Delhi - James St (MORATORIUM UNTIL 2026) - Southeast - Wat	30258	Value Driven	-	-	(1,005)	(1,205)	200	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	182.48	0.00	0.00	0.00	0.13	0.00	0.00	15.27	2.19
Emergent	Distribution Pipe	Div. 06 - Brantford - Wilkes St (MORATORIUM UNTIL 2027) - Southeast -	30257	Value Driven	-	-	(1,517)	(1,586)	69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.15	0.00	0.00	0.00	0.44	0.00	0.00	6.94	0.98
Existing Investment	Distribution Pipe	Div. 06 - Brantford - Toll Gate Rd - Southeast - Waterloo - 1314	30256	Value Driven	-	-	(1,157)	(1,604)	447	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	395.67	0.00	0.00	0.00	33.48	0.00	0.00	15.96	2.19
Emergent	Distribution Pipe	Div. 06 - Brantford - St Paul Ave (MORATORIUM UNTIL 2025) - Southeas	30254	Value Driven	-	-	(657)	(1,160)	502	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	462.25	0.00	0.00	0.00	28.42	0.00	0.00	10.17	1.42
Existing Investment	Distribution Pipe	Div. 06 - Brantford - St George St 2 - Southeast - Waterloo - 1386	30253	Value Driven	-	-	(1,919)	(2,233)	314	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	282.09	0.00	0.00	0.00	22.26	0.00	0.00	8.63	1.24
Existing Investment	Distribution Pipe	Div. 06 - Brantford - St George St - Southeast - Waterloo - 1312	30252	Value Driven	-	-	(1,776)	(2,181)	406	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	364.64	0.00	0.00	0.00	29.79	0.00	0.00	9.77	1.39
Emergent	Distribution Pipe	Div. 16 - Hamilton - Barton St E (MORATORIUM UNTIL 2027) - Hamilton -	30403	Value Driven	-	-	(1,179)	(1,563)	384	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	342.84	0.00	0.00	0.00	27.59	0.00	0.00	12.12	1.73
Existing Investment	Distribution Pipe	Div. 16 - Haldimand - Dunnville - Central Lane - Hamilton - 1361	30398	Value Driven	-	-	(1,336)	(1,767)	432	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	395.93	0.00	0.00	0.00	0.43	0.00	0.00	30.33	4.99
Existing Investment	Distribution Pipe	Div. 17 - Halton - Burlington - Guelph Line - Hamilton - 2026	30414	Value Driven	-	-	(1,386)	(2,348)	962	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	689.57	0.00	0.00	0.00	260.17	0.00	0.00	11.06	1.60
Existing Investment	Distribution Pipe	Emery St E (MORATORIUM UNTIL 2026) - Southwest - London - 1472	30292	Value Driven	-	-	(1,737)	(1,795)	58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.71	0.00	0.00	0.00	0.31	0.00	0.00	4.53	0.64
Emergent	Distribution Pipe	Fanshawe Park Rd E - Southwest - London - 1478	30293	Value Driven	-	-	(1,759)	(1,944)	185	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	172.69	0.00	0.00	0.00	3.87	0.00	0.00	7.96	0.85
Emergent	Distribution Pipe	Div. 06 - Brantford - Spalding Dr - Southeast - Waterloo - 1387	30251	Value Driven	-	-	(2,293)	(2,354)	61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.56	0.00	0.00	0.00	0.44	0.00	0.00	2.59	0.40
Emergent	Distribution Pipe	Div. 06 - Brantford - N Park St (MORATORIUM UNTIL 2026) - Southeast -	30249	Value Driven	-	-	(1,530)	(1,689)	159	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	148.32	0.00	0.00	0.00	0.73	0.00	0.00	8.62	1.23
Existing Investment	Distribution Pipe	Div. 06 - Brantford - Greenwich St - Southeast - Waterloo - 1332	30248	Value Driven	-	-	(1,382)	(1,453)	71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	64.00	0.00	0.00	0.00	3.59	0.00	0.00	2.62	0.40
Emergent	Distribution Pipe	Div. 06 - Brantford - Grand St (MORATORIUM UNTIL 2026) - Southeast -	30247	Value Driven	-	-	(792)	(902)	109	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	99.03	0.00	0.00	0.00	0.23	0.00	0.00	8.78	1.26
Existing Investment	Distribution Pipe	Tanguay Ave - Northeast - 1280	30232	Value Driven	-	-	(412)	(424)	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.58	0.00	0.00	0.00	0.05	0.00	0.00	1.09	0.14
Existing Investment	Distribution Pipe	Div. 06 - Brantford - Franklin St - Southeast - Waterloo - 1388	30246	Value Driven	-	-	(1,734)	(1,865)	131	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	117.91	0.00	0.00	0.00	8.28	0.00	0.00	3.85	0.55
Existing Investment	Distribution Pipe	Div. 06 - Brantford - Ewing Dr - Southeast - Waterloo - 1316	30245	Value Driven	-	-	(648)	(1,491)	844	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	713.75	0.00	0.00	0.00	109.71	0.00	0.00	17.72	2.46
Existing Investment	Distribution Pipe	Halton - Oakville - 6th Line-Phase 1- VSM Replacement	30415	Value Driven	$ 31,389	-	(881)	(913)	32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.03	0.00	0.00	0.00	0.07	0.00	0.00	2.07	0.28
Existing Investment	Distribution Pipe	Div. 16 - Hamilton - Province St N - Hamilton - 1416	30410	Value Driven	-	-	(514)	(557)	44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.18	0.00	0.00	0.00	0.05	0.00	0.00	2.26	0.33
Emergent	Distribution Pipe	Div. 17 - Halton - Oakville - Kerr St (MORATORIUM UNTIL 2028) - Hamilt	30416	Value Driven	-	-	(859)	(1,422)	563	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	514.00	0.00	0.00	0.00	1.64	0.00	0.00	43.18	4.52
Existing Investment	Distribution Pipe	Wickstead Ave (MORATORIUM UNTIL 2026) - Northeast - 1510	30233	Value Driven	-	-	(1,146)	(1,183)	37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.77	0.00	0.00	0.00	0.21	0.00	0.00	2.60	0.31
Emergent	Distribution Pipe	Malden Rd 3 - Southwest - Windsor - 1661	30027	Value Driven	-	-	(857)	(903)	45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.10	0.00	0.00	0.00	0.08	0.00	0.00	4.63	0.67
Existing Investment	Distribution Pipe	Malden Rd 2 - Southwest - Windsor - 1660	30026	Value Driven	-	-	(985)	(1,029)	44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.10	0.00	0.00	0.00	0.07	0.00	0.00	3.46	0.51
Existing Investment	Distribution Pipe	Stratford-Mercer St from Caledonia to Brittania-1757	30443	Value Driven	-	-	(166)	(170)	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.75	0.00	0.00	0.00	0.01	0.00	0.00	0.33	0.05
Emergent	Distribution Pipe	Stratford-Queen St - Brunwick to Douro-1770	30455	Value Driven	-	-	(196)	(201)	6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.03	0.00	0.00	0.00	0.01	0.00	0.00	0.43	0.06
Emergent	Distribution Pipe	Malden Rd 1 - Southwest - Windsor - 1659	30025	Value Driven	-	-	(825)	(859)	34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.93	0.00	0.00	0.00	0.11	0.00	0.00	3.39	0.47
Existing Investment	Distribution Pipe	Front St - Southwest - London - 1393	30294	Value Driven	-	-	(519)	(894)	375	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	344.36	0.00	0.00	0.00	0.06	0.00	0.00	27.01	3.88
Emergent	Distribution Pipe	Lauzon Rd - Southwest - Windsor - 2025	30023	Value Driven	-	-	(1,267)	(1,283)	15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.94	0.00	0.00	0.00	3.22	0.00	0.00	0.29	0.04
Emergent	Distribution Pipe	Front St W - Southwest - London - 1544	30295	Value Driven	-	-	(1,458)	(1,579)	121	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	110.98	0.00	0.00	0.00	0.34	0.00	0.00	8.51	1.35
Existing Investment	Distribution Pipe	Adelaide St N (EXECUTE 2024 - MUNICIPAL WORK PLANNED FOR 2025) -	30275	Value Driven	-	-	(1,374)	(1,553)	179	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	162.23	0.00	0.00	0.00	0.90	0.00	0.00	14.74	1.62
Existing Investment	Distribution Pipe	KING: King St W, Cobourg, VSM Replacement	30470	Value Driven	-	$ 63,150	(1,501)	(1,521)	19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.24	0.00	0.00	0.00	0.25	0.00	0.00	1.52	0.21
Existing Investment	Distribution Pipe	Clarke Rd (EXECUTE 2025 - MUNICIPAL WORK PLANNED FOR 2025) - Sou	30284	Value Driven	-	-	(1,383)	(1,584)	201	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	192.89	0.00	0.00	0.00	2.37	0.00	0.00	4.28	1.16
Emergent	Distribution Pipe	Front St W 2 - Southwest - London - 1547	30296	Value Driven	-	-	(1,211)	(1,282)	71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	64.22	0.00	0.00	0.00	0.23	0.00	0.00	5.44	0.83
Emergent	Distribution Pipe	Karl Pl - Southwest - Windsor - 1360	30020	Value Driven	-	-	(1,139)	(1,204)	65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.29	0.00	0.00	0.00	0.28	0.00	0.00	3.84	0.51
Emergent	Distribution Pipe	Homedale Blvd - Southwest - Windsor - 1287	30019	Value Driven	-	-	(255)	(1,392)	1,138	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,062.16	0.00	0.00	0.00	0.65	0.00	0.00	65.82	9.03
Existing Investment	Distribution Pipe	Wallace Ave - Southwest - Windsor - 1350	30018	Value Driven	-	-	(951)	(1,048)	97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	83.30	0.00	0.00	0.00	0.10	0.00	0.00	11.72	1.68
Existing Investment	Distribution Pipe	Div. 06 - Brantford - Dundas St E - Southeast - Waterloo - 1827	30243	Value Driven	-	-	(916)	(1,001)	85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	79.14	0.00	0.00	0.00	1.36	0.00	0.00	4.12	0.59
Emergent	Distribution Pipe	Grand Marais Rd W - Southwest - Windsor -Phase 1	30017	Value Driven	-	-	(564)	(570)	5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.15	0.00	0.00	0.00	1.03	0.00	0.00	0.10	0.01
Existing Investment	Distribution Pipe	Giles Blvd E - Southwest - Windsor - 1845	30016	Value Driven	-	-	(56)	(365)	308	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	289.79	0.00	0.00	0.00	6.44	0.00	0.00	10.71	1.53
Existing Investment	Distribution Pipe	WIND: Elm Ave, Windsor, VSM Replacement	30015	Value Driven	$ 1,515	-	(313)	(1,633)	1,320	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,241.61	0.00	0.00	0.00	0.36	0.00	0.00	69.42	8.30
Existing Investment	Distribution Pipe	Elinor St - Southwest - Windsor - 1279	30014	Value Driven	-	-	(311)	(486)	176	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	164.56	0.00	0.00	0.00	0.05	0.00	0.00	9.57	1.39
Existing Investment	Distribution Pipe	Edgar St - Southwest - Windsor - 1277	30013	Value Driven	-	-	(686)	(1,313)	627	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	583.08	0.00	0.00	0.00	10.46	0.00	0.00	29.49	4.23
Emergent	Distribution Pipe	Glendon Dr - Southwest - London - 1465	30297	Value Driven	-	-	(1,966)	(2,005)	39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.38	0.00	0.00	0.00	0.03	0.00	0.00	3.89	0.57
Existing Investment	Distribution Pipe	Downie St 3 - Southwest - London - 1808	30464	Value Driven	-	-	(476)	(476)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Gordon Ave - Southwest - London - 1482	30299	Value Driven	-	-	(1,310)	(1,710)	400	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	362.36	0.00	0.00	0.00	0.35	0.00	0.00	34.13	3.66
Existing Investment	Distribution Pipe	Greenwood Ave - Southwest - London - 1428	30300	Value Driven	-	-	(603)	(1,696)	1,094	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,019.40	0.00	0.00	0.00	3.46	0.00	0.00	62.12	8.60

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
Existing Investment	Distribution Pipe	WIND: Ducharme St, Windsor, VSM Replacement	30012	Value Driven	$ 3,362	-	(1,486)	(1,641)	154	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	140.65	0.00	0.00	0.00	0.15	0.00	0.00	11.98	1.72
Existing Investment	Distribution Pipe	Front St (MORATORIUM UNTIL 2025) -Belleville-1592	30421	Value Driven	-	-	(2,052)	(2,087)	35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.75	0.00	0.00	0.00	0.21	0.00	0.00	1.94	0.25
Emergent	Distribution Pipe	Hill St - Southwest - London - 1567	30302	Value Driven	-	-	(1,772)	(1,860)	88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	80.32	0.00	0.00	0.00	0.20	0.00	0.00	6.52	0.95
Emergent	Distribution Pipe	Dubois Ave - Southwest - Windsor - 1385	30011	Value Driven	-	-	(889)	(962)	72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	64.79	0.00	0.00	0.00	0.11	0.00	0.00	6.51	0.93
Emergent	Distribution Pipe	Hughes St - Southwest - London - 1394	30303	Value Driven	-	-	(657)	(754)	97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	88.84	0.00	0.00	0.00	0.09	0.00	0.00	7.39	1.06
Existing Investment	Distribution Pipe	Wortley Rd - Southwest - London - 1474	30329	Value Driven	-	-	(512)	(554)	43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.00	0.00	0.00	0.00	0.21	0.00	0.00	2.97	0.43
Emergent	Distribution Pipe	WATE: High St, Brant, VSM Replacement	30235	Value Driven	-	-	(627)	(673)	46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.01	0.00	0.00	0.00	0.09	0.00	0.00	2.53	0.37
Emergent	Distribution Pipe	Dauw Ave - Southwest - Windsor - 1384	30009	Value Driven	-	-	(446)	(478)	32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.86	0.00	0.00	0.00	0.03	0.00	0.00	2.72	0.39
Emergent	Distribution Pipe	Huron St - Southwest - London - 1525	30304	Value Driven	-	-	(1,638)	(1,801)	163	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	150.01	0.00	0.00	0.00	0.31	0.00	0.00	11.05	1.53
Emergent	Distribution Pipe	Iroquois Ave (MORATORIUM UNTIL 2026) - Southwest - London - 1519	30305	Value Driven	-	-	(875)	(921)	46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.80	0.00	0.00	0.00	0.09	0.00	0.00	3.64	0.52
Existing Investment	Distribution Pipe	Aberdeen St - Southwest - Windsor - 1356	30001	Value Driven	-	-	(671)	(799)	128	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	117.16	0.00	0.00	0.00	0.05	0.00	0.00	9.19	1.30
Emergent	Distribution Pipe	Jacqueline St - Southwest - London - 1426	30306	Value Driven	-	-	(1,519)	(2,209)	690	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	642.98	0.00	0.00	0.00	26.17	0.00	0.00	18.17	2.56
Existing Investment	Distribution Pipe	Matchedash St N 2 (MORATORIUM UNTIL 2026) - Northeast - 1720	30225	Value Driven	-	-	(110)	(116)	5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.69	0.00	0.00	0.00	0.01	0.00	0.00	0.43	0.06
Emergent	Distribution Pipe	Kains St (MORATORIUM UNTIL 2028) - Southwest - London - 1476	30308	Value Driven	-	-	(767)	(910)	143	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	134.77	0.00	0.00	0.00	0.10	0.00	0.00	7.37	1.03
Emergent	Distribution Pipe	Percival St-Port Hope-1593	30433	Value Driven	-	-	(1,681)	(1,732)	50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.34	0.00	0.00	0.00	0.72	0.00	0.00	2.86	0.42
Existing Investment	Distribution Pipe	Matchedash St N 1 (MORATORIUM UNTIL 2026) - Northeast - 1719	30224	Value Driven	-	-	(205)	(215)	10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.06	0.00	0.00	0.00	0.03	0.00	0.00	0.74	0.11
Emergent	Distribution Pipe	Lorne Ave (MORATORIUM UNTIL 2027) - Southwest - London - 1526	30309	Value Driven	-	-	(1,238)	(1,348)	109	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.34	0.00	0.00	0.00	0.35	0.00	0.00	7.67	1.10
Emergent	Distribution Pipe	Moore Line - Southwest - London - 1516	30310	Value Driven	-	-	(1,741)	(1,982)	242	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	230.43	0.00	0.00	0.00	0.75	0.00	0.00	9.00	1.54
Emergent	Distribution Pipe	Moore Line 2 - Southwest - London - 1564	30311	Value Driven	-	-	(1,250)	(1,339)	89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	87.60	0.00	0.00	0.00	0.28	0.00	0.00	0.48	0.58
Emergent	Distribution Pipe	Stratford-Perth St - Taylor to Borden-1767	30452	Value Driven	-	-	(217)	(229)	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.96	0.00	0.00	0.00	0.03	0.00	0.00	1.00	0.14
Existing Investment	Distribution Pipe	Mornington Ave - Southwest - London - 1531	30312	Value Driven	-	-	(3,089)	(3,250)	161	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	150.20	0.00	0.00	0.00	1.24	0.00	0.00	8.18	1.18
Emergent	Distribution Pipe	Walton St (MORATORIUM UNTIL 2028) - Cornwall - Eastern - 1740	30438	Value Driven	-	-	(979)	(1,024)	45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.66	0.00	0.00	0.00	0.13	0.00	0.00	3.61	0.51
Existing Investment	Distribution Pipe	Old Lakeshore Rd - Southwest - London - 1572	30313	Value Driven	-	-	(645)	(716)	71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	65.58	0.00	0.00	0.00	0.04	0.00	0.00	4.88	0.70
Emergent	Distribution Pipe	Stratford-Avondale Ave from Huron to Cemetary-1759	30444	Value Driven	-	-	(213)	(222)	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.66	0.00	0.00	0.00	0.01	0.00	0.00	0.71	0.10
Emergent	Distribution Pipe	Pinewood Dr - Southwest - London - 1523	30314	Value Driven	-	-	(1,113)	(1,168)	54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.29	0.00	0.00	0.00	0.10	0.00	0.00	4.39	0.64
Existing Investment	Distribution Pipe	North Alley-Ganonoque-1468	30432	Value Driven	-	-	(1,253)	(1,275)	21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.53	0.00	0.00	0.00	0.33	0.00	0.00	0.54	0.08
Emergent	Distribution Pipe	Ridout St N (MORATORIUM UNTIL 2028) - Southwest - London - 1533	30315	Value Driven	-	-	(1,715)	(1,918)	203	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	174.81	0.00	0.00	0.00	21.30	0.00	0.00	5.85	0.71
Existing Investment	Distribution Pipe	Main St - Gananoque - Eastern - 1737	30428	Value Driven	-	-	(889)	(958)	69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.61	0.00	0.00	0.00	0.12	0.00	0.00	1.93	0.29
Existing Investment	Distribution Pipe	Ridout St S (EXECUTE 2024) - Southwest - London - 1470	30316	Value Driven	-	-	(659)	(1,011)	352	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	321.07	0.00	0.00	0.00	2.34	0.00	0.00	24.91	3.53
Emergent	Distribution Pipe	Dundas St 3 (MORATORIUM UNTIL 2029) - Southwest - London - 1521	30289	Value Driven	-	-	(861)	(963)	102	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	95.03	0.00	0.00	0.00	0.24	0.00	0.00	5.98	0.71
Emergent	Distribution Pipe	King St W (MORATORIUM UNTIL 2030) - Ganonoque - Eastern - 1748	30427	Value Driven	-	-	(974)	(1,047)	73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.33	0.00	0.00	0.00	0.04	0.00	0.00	2.19	0.30
Emergent	Distribution Pipe	Wall St-Trent-1271	30437	Value Driven	-	-	(2,759)	(2,842)	83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	75.33	0.00	0.00	0.00	1.06	0.00	0.00	5.45	0.79
Existing Investment	Distribution Pipe	Div. 16 - Haldimand - Canborough - Smithville Rd - Hamilton - 1488	30397	Value Driven	-	-	(1,316)	(1,435)	120	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	112.22	0.00	0.00	0.00	0.07	0.00	0.00	6.40	0.97
Existing Investment	Distribution Pipe	Hickory St-Ganonoque-1454	30426	Value Driven	-	-	(844)	(933)	89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86.14	0.00	0.00	0.00	0.09	0.00	0.00	2.57	0.37
Existing Investment	Distribution Pipe	Div. 16 - Haldimand - Caledonia - Argyle St S - Hamilton - 1486	30396	Value Driven	-	-	(1,540)	(2,021)	481	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	438.15	0.00	0.00	0.00	0.44	0.00	0.00	37.40	5.25
Existing Investment	Distribution Pipe	Div. 06 - Brantford - Elgin St - Southeast - Waterloo - 1296	30244	Value Driven	-	-	(1,657)	(2,001)	345	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	322.86	0.00	0.00	0.00	6.16	0.00	0.00	13.58	2.16
Emergent	Distribution Pipe	Div. 06 - Brantford - Colborne St - Southeast - Waterloo - 1817	30242	Value Driven	-	-	(1,158)	(1,239)	80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	74.55	0.00	0.00	0.00	0.48	0.00	0.00	4.87	0.55
Emergent	Distribution Pipe	Div. 06 - Brantford - Charing Cross St (MORATORIUM UNTIL 2026) - Sou	30241	Value Driven	-	-	(1,108)	(1,167)	58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.77	0.00	0.00	0.00	0.10	0.00	0.00	4.75	0.67
Emergent	Distribution Pipe	Div. 06 - Brantford - Catherine Ave - Souheast - Waterloo - 1321	30240	Value Driven	-	-	(1,246)	(1,338)	93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	87.25	0.00	0.00	0.00	1.83	0.00	0.00	3.24	0.46
Existing Investment	Distribution Pipe	Div. 06 - Brantford - Balmoral Dr - Southeast - Waterloo - 1291	30238	Value Driven	-	-	(668)	(1,257)	589	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	487.80	0.00	0.00	0.00	91.95	0.00	0.00	7.96	1.14
Emergent	Distribution Pipe	Downie St 2 - Southwest - London - 1807	30463	Value Driven	-	-	(1,653)	(1,653)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	Stratford - St. David to Cambria-1769	30453	Value Driven	-	-	(175)	(179)	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.98	0.00	0.00	0.00	0.01	0.00	0.00	0.34	0.05
Emergent	Distribution Pipe	Mary St 2 - Northeast - 1709	30223	Value Driven	-	-	(681)	(710)	29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.36	0.00	0.00	0.00	0.13	0.00	0.00	2.25	0.32
Existing Investment	Distribution Pipe	Div. 06 - Brantford - Abigail Ave - Southeast - Waterloo - 1309	30237	Value Driven	-	-	(494)	(1,222)	728	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	656.81	0.00	0.00	0.00	55.41	0.00	0.00	13.45	1.92
Emergent	Distribution Pipe	Div. 06 - Brant - Park Rd N - Southeast - Waterloo - 1315	30236	Value Driven	-	-	14,090	(2,537)	16,627	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16,204.38	0.00	0.00	0.00	39.69	0.00	0.00	308.69	74.64
Existing Investment	Distribution Pipe	Downie St 1 - Southwest - London - 1806	30462	Value Driven	-	-	(1,169)	(1,260)	91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	82.76	0.00	0.00	0.00	0.83	0.00	0.00	6.68	0.90
Existing Investment	Distribution Pipe	Div. 06 - Brant - Broadway St W - Southeast - Waterloo - 1378	30234	Value Driven	-	-	(1,839)	(1,937)	98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	89.04	0.00	0.00	0.00	1.67	0.00	0.00	6.39	1.02
Existing Investment	Distribution Pipe	Stratford-Mowat St from W. Gore to Brydges-1760	30445	Value Driven	-	-	(350)	(363)	13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.60	0.00	0.00	0.00	0.02	0.00	0.00	0.97	0.14
Emergent	Distribution Pipe	Sunset Dr (MORATORIUM UNTIL 2025) - Southwest - London - 1445	30322	Value Driven	-	-	(630)	(1,055)	425	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	401.80	0.00	0.00	0.00	1.51	0.00	0.00	19.21	2.62
Existing Investment	Distribution Pipe	Colborne St W 2 - Northeast - 1683	30201	Value Driven	-	-	(576)	(604)	27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24.73	0.00	0.00	0.00	0.06	0.00	0.00	2.14	0.31
Emergent	Distribution Pipe	Dearness Dr - Southwest - London - 1396	30286	Value Driven	-	-	(1,530)	(2,718)	1,188	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,093.88	0.00	0.00	0.00	1.32	0.00	0.00	81.99	10.97
Emergent	Distribution Pipe	Harriett St (MORATORIUM UNTIL 2028)-Belleville-1600	30425	Value Driven	-	-	(982)	(1,025)	43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.47	0.00	0.00	0.00	0.12	0.00	0.00	2.77	0.39
Emergent	Distribution Pipe	Wharncliffe Rd S - Southwest - London - 1451	30326	Value Driven	-	-	(1,481)	(1,593)	113	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	104.17	0.00	0.00	0.00	0.12	0.00	0.00	7.58	0.95
Emergent	Distribution Pipe	Grove St-Belleville-1591	30424	Value Driven	-	-	(1,445)	(1,472)	27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.30	0.00	0.00	0.00	0.06	0.00	0.00	1.52	0.21
Existing Investment	Distribution Pipe	Sudbury - Janet St Phase 2 - Northeast - VSM 1700	30215	Value Driven	-	-	(806)	(843)	37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.93	0.00	0.00	0.00	0.08	0.00	0.00	3.13	0.42
Existing Investment	Distribution Pipe	Garden Alley 2-Ganonoque-1494	30423	Value Driven	-	-	(1,567)	(1,637)	69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.72	0.00	0.00	0.00	0.10	0.00	0.00	2.32	0.34
Existing Investment	Distribution Pipe	Wardsville Line - Southwest - London - 1797	736302	Value Driven	-	-	(4,908)	(4,954)	46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.71	0.00	0.00	0.00	0.18	0.00	0.00	0.89	0.29
Emergent	Distribution Pipe	Garden Alley 1-Ganonoque-1460	30422	Value Driven	-	-	(1,446)	(1,561)	115	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	111.01	0.00	0.00	0.00	0.59	0.00	0.00	3.23	0.46
Existing Investment	Distribution Pipe	Ross St (MORATORIUM UNTIL 2025) - Southwest - London - 1560	30317	Value Driven	-	-	(468)	(575)	107	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	101.03	0.00	0.00	0.00	0.06	0.00	0.00	5.02	0.74
Emergent	Distribution Pipe	Talbot St (MORATORIUM UNTIL 2028) - Southwest - London - 1433	30323	Value Driven	-	-	(1,622)	(1,919)	296	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	278.73	0.00	0.00	0.00	0.71	0.00	0.00	14.74	2.17
Existing Investment	Distribution Pipe	Div. 16 - Hamilton - Wentworth St S 2 - Hamilton - 1743	30413	Value Driven	-	-	(439)	(644)	205	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	190.11	0.00	0.00	0.00	0.60	0.00	0.00	12.58	1.72
Emergent	Distribution Pipe	Div. 16 - Hamilton - Wentworth St S 1 - Hamilton - 1742	30412	Value Driven	-	-	(520)	(558)	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.91	0.00	0.00	0.00	0.18	0.00	0.00	2.63	0.38
Existing Investment	Distribution Pipe	Sudbury - Janet St Phase 1 - Northeast - VSM Replacement	30214	Value Driven	$ 55,106	-	(785)	(814)	29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.68	0.00	0.00	0.00	0.08	0.00	0.00	2.40	0.34
Existing Investment	Distribution Pipe	Mcgill St-Trenton-1596	30430	Value Driven	-	-	(886)	(916)	31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.35	0.00	0.00	0.00	0.08	0.00	0.00	2.20	0.31
Existing Investment	Distribution Pipe	Div. 16 - Hamilton - Centennial Pkwy N - Hamilton - 1747	30404	Value Driven	-	-	(1,000)	(1,398)	398	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	376.52	0.00	0.00	0.00	2.18	0.00	0.00	17.28	2.47
Emergent	Distribution Pipe	N Murray St-Trenton-1595	30431	Value Driven	-	-	(1,710)	(1,778)	68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.32	0.00	0.00	0.00	2.34	0.00	0.00	3.66	0.52
Existing Investment	Distribution Pipe	Hilda St 2 - Northeast - 1698	30213	Value Driven	-	-	(794)	(816)	22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.47	0.00	0.00	0.00	0.09	0.00	0.00	1.81	0.26
Emergent	Distribution Pipe	Sarnia Rd (MORATORIUM UNTIL 2029) - Southwest - London - 1464	30318	Value Driven	-	-	(813)	(881)	68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	62.22	0.00	0.00	0.00	2.73	0.00	0.00	2.85	0.40
Existing Investment	Distribution Pipe	Victoria Ave-Ganonoque-1457	30436	Value Driven	-	-	(1,184)	(1,262)	78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	74.85	0.00	0.00	0.00	0.15	0.00	0.00	2.36	0.33
Existing Investment	Distribution Pipe	Stratford-Daly Ave with Birmingham to Worsley-1756	30442	Value Driven	-	-	(61)	(66)	5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.26	0.00	0.00	0.00	0.01	0.00	0.00	0.34	0.05
Emergent	Distribution Pipe	Centre St - Southwest - London - 1479	30281	Value Driven	-	-	(868)	(955)	87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	78.42	0.00	0.00	0.00	0.37	0.00	0.00	7.77	0.93
Existing Investment	Distribution Pipe	Mary St 1 - Northeast - 1708	30222	Value Driven	-	-	(827)	(850)	24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.48	0.00	0.00	0.00	0.65	0.00	0.00	1.42	0.20
Existing Investment	Distribution Pipe	Maher St 2 - Northeast - 1703	30221	Value Driven	-	-	(365)	(382)	17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.81	0.00	0.00	0.00	0.02	0.00	0.00	1.39	0.20
Existing Investment	Distribution Pipe	Maher St 1 - Northeast - 1701	30220	Value Driven	-	-	(744)	(762)	17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.77	0.00	0.00	0.00	0.17	0.00	0.00	1.26	0.18
Existing Investment	Distribution Pipe	Stratford-Huron St-Matilda to Douglas Phase 2-1758	30441	Value Driven	-	-	(1,224)	(1,261)	37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.96	0.00	0.00	0.00	0.09	0.00	0.00	2.98	0.41
Emergent	Distribution Pipe	Stratford-Perth St - Downie to Taylor-1761	30446	Value Driven	-	-	(182)	(189)	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.80	0.00	0.00	0.00	0.02	0.00	0.00	0.57	0.08
Emergent	Distribution Pipe	Taylor St Shallow Main - Huron St to Cheapside St - Southwest - London	30440	Value Driven	-	-	(877)	(913)	36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.06	0.00	0.00	0.00	0.94	0.00	0.00	1.90	0.25
Existing Investment	Distribution Pipe	Laforest Ave - Northeast - 1270	30219	Value Driven	-	-	(554)	(592)	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.64	0.00	0.00	0.00	0.60	0.00	0.00	2.98	0.39
Emergent	Distribution Pipe	Stratford-W Gore St - St. Vincent to John-1762	30447	Value Driven	-	-	(103)	(106)	3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.79	0.00	0.00	0.00	0.02	0.00	0.00	0.23	0.03
Emergent	Distribution Pipe	Lambeth - Southwest - London - 1776	30439	Value Driven	-	-	(1,352)	(2,076)	724	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	668.44	0.00	0.00	0.00	0.92	0.00	0.00	47.80	6.88
Existing Investment	Distribution Pipe	E Centre St - Southwest - London - 1412	30290	Value Driven	-	-	(813)	(935)	121	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	110.99	0.00	0.00	0.00	0.10	0.00	0.00	8.82	1.26
Emergent	Distribution Pipe	Stratford-Water St - Queen to Parkview-1763	30448	Value Driven	-	-	(101)	(105)	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.43	0.00	0.00	0.00	0.01	0.00	0.00	0.28	0.04
Existing Investment	Distribution Pipe	Courthouse Sq - Southwest - London - 1802	30461	Value Driven	-	-	(637)	(669)	33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.12	0.00	0.00	0.00	0.03	0.00	0.00	2.27	0.35
Existing Investment	Distribution Pipe	Hamilton - Rosemary Ave - VSM Replacement	30411	Value Driven	-	$ 69,465	(470)	(637)	168	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	157.30	0.00	0.00	0.00	0.93	0.00	0.00	8.26	1.30
Emergent	Distribution Pipe	WATE: Ontario St, Brantford, VSM Replacement	30250	Value Driven	-	-	(876)	(944)	67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.37	0.00	0.00	0.00	0.08	0.00	0.00	5.08	0.72
Existing Investment	Distribution Pipe	Hilda St 1 - Northeast - 1696	30212	Value Driven	-	-	(867)	(890)	23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.61	0.00	0.00	0.00	0.14	0.00	0.00	1.88	0.25
Emergent	Distribution Pipe	Stratford-Birmingham - Cambria to Daly-1764	30449	Value Driven	-	-	(211)	(220)	9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.32	0.00	0.00	0.00	0.05	0.00	0.00	0.68	0.10
Emergent	Distribution Pipe	Woods St - Southwest - Windsor - 1337	30045	Value Driven	-	-	(1,203)	(1,367)	164	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	151.75	0.00	0.00	0.00	1.28	0.00	0.00	9.79	1.38
Existing Investment	Distribution Pipe	Walker Rd - Southwest - Windsor - 1333	30044	Value Driven	-	-	(1,318)	(1,686)	368	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	352.97	0.00	0.00	0.00	6.10	0.00	0.00	7.54	1.16
Existing Investment	Distribution Pipe	Wilton Grove Rd - Southwest - London - 1395	30327	Value Driven	-	-	(1,456)	(1,814)	358	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	327.49	0.00	0.00	0.00	2.29	0.00	0.00	25.75	2.58
Emergent	Distribution Pipe	Stratford-Brunswick St - King to Romeo-1765	30450	Value Driven	-	-	(221)	(230)	9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.26	0.00	0.00	0.00	0.16	0.00	0.00	0.39	0.05
Emergent	Distribution Pipe	Stratford-Douglas St-Huntington to John-1768	30454	Value Driven	-	-	15	(403)	418	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	382.25	0.00	0.00	0.00	1.97	0.00	0.00	29.27	4.23
Existing Investment	Distribution Pipe	Tecumseh Rd W 2 - Southwest - Windsor - 1492	30042	Value Driven	-	-	(1,258)	(1,435)	176	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	153.31	0.00	0.00	0.00	8.13	0.00	0.00	13.17	1.79
Existing Investment	Distribution Pipe	Talbot Rd - Southwest - Windsor - 1369	30039	Value Driven	-	-	(1,124)	(1,192)	68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	62.62	0.00	0.00	0.00	0.15	0.00	0.00	4.59	0.71
Existing Investment	Distribution Pipe	Georgina Ave 2 - Northeast - 1695	30211	Value Driven	-	-	(738)	(762)	23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.93	0.00	0.00	0.00	0.07	0.00	0.00	1.96	0.28
Existing Investment	Distribution Pipe	King St W (MORATORIUM UNTIL 2026) - Northeast - 1239	30218	Value Driven	-	-	(748)	(780)	33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.49	0.00	0.00	0.00	0.05	0.00	0.00	2.67	0.38
Existing Investment	Distribution Pipe	Windsor Ave (EXECUTE BY 2025 - MUNICIPAL WORK PLANNED FOR 202	30328	Value Driven	-	-	(1,383)	(1,457)	73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	68.37	0.00	0.00	0.00	0.13	0.00	0.00	4.17	0.59
Existing Investment	Distribution Pipe	North Bay - Galt St Phase 2 - Northeast - VSM 1691	30209	Value Driven	-	-	(938)	(978)	40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.92	0.00	0.00	0.00	0.05	0.00	0.00	3.45	0.47
Existing Investment	Distribution Pipe	Rourke Line Rd - Southwest - Windsor - 1373	30036	Value Driven	-	-	(1,152)	(1,210)	58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.67	0.00	0.00	0.00	0.21	0.00	0.00	5.11	0.73

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
Existing Investment	Distribution Pipe	Riverside Dr E - Southwest - Windsor - 1357	30035	Value Driven	-	-	(803)	(913)	110	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	102.96	0.00	0.00	0.00	0.12	0.00	0.00	6.13	0.88
Existing Investment	Distribution Pipe	Div. 16 - Haldimand - Fisherville - Erie Ave N 1 - Hamilton - 1728	30399	Value Driven	-	-	(1,472)	(1,489)	17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.71	0.00	0.00	0.00	0.05	0.00	0.00	2.10	0.32
Existing Investment	Distribution Pipe	North Bay - Galt St Phase 1 - Northeast - VSM Replacement	30208	Value Driven	$ 61,629	-	(782)	(806)	24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.62	0.00	0.00	0.00	0.04	0.00	0.00	2.25	0.30
Emergent	Distribution Pipe	Dundas St (MORATORIUM UNTIL 2030) - Southwest - London - 1411	30287	Value Driven	-	-	(995)	(1,113)	118	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	111.87	0.00	0.00	0.00	0.54	0.00	0.00	4.91	0.68
Emergent	Distribution Pipe	St Felix St (MORATORIUM UNTIL 2028) - Cornwall - Eastern - 1739	30435	Value Driven	-	-	(822)	(866)	44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.74	0.00	0.00	0.00	0.10	0.00	0.00	3.34	0.47
Existing Investment	Distribution Pipe	River View Line - Southwest - Windsor - 1381	30034	Value Driven	-	-	(170)	(194)	23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.89	0.00	0.00	0.00	0.01	0.00	0.00	1.35	0.24
Emergent	Distribution Pipe	Stratford-Laurier St - East Gore to Norfolk-1775	30460	Value Driven	-	-	(79)	(88)	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.46	0.00	0.00	0.00	0.01	0.00	0.00	0.61	0.09
Existing Investment	Distribution Pipe	Hamilton - Oak Ave - VSM Replacement	30409	Value Driven	-	-	(712)	(779)	66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.97	0.00	0.00	0.00	0.12	0.00	0.00	3.80	0.56
Existing Investment	Distribution Pipe	Bridge St W-Napanee-1602	30419	Value Driven	-	-	(1,874)	(1,931)	57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.03	0.00	0.00	0.00	0.26	0.00	0.00	4.50	0.66
Emergent	Distribution Pipe	Stratford-McDonald St - Willow to Devon-1766	30451	Value Driven	-	-	(180)	(184)	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.05	0.00	0.00	0.00	0.01	0.00	0.00	0.34	0.05
Existing Investment	Distribution Pipe	Ferguson Ave 2 - Northeast - 1688	30207	Value Driven	-	-	(881)	(911)	30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.38	0.00	0.00	0.00	0.12	0.00	0.00	2.28	0.34
Existing Investment	Distribution Pipe	Augustus St - Cornwall - Eastern - 1729	30418	Value Driven	-	-	(995)	(1,035)	40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.60	0.00	0.00	0.00	0.13	0.00	0.00	3.36	0.44
Existing Investment	Distribution Pipe	Ferguson Ave 1 - Northeast - 1686	30206	Value Driven	-	-	(753)	(786)	33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.22	0.00	0.00	0.00	0.13	0.00	0.00	2.34	0.36
Existing Investment	Distribution Pipe	4th Ave E - Northeast - 1302	30197	Value Driven	-	-	(708)	(746)	38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.25	0.00	0.00	0.00	0.09	0.00	0.00	3.14	0.45
Existing Investment	Distribution Pipe	Cheapside St - Southwest - London - 1453	30282	Value Driven	-	-	(1,014)	(1,194)	180	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	169.70	0.00	0.00	0.00	0.07	0.00	0.00	8.84	1.26
Existing Investment	Distribution Pipe	Farah Ave - Northeast - 1288	30205	Value Driven	-	-	(586)	(608)	22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.04	0.00	0.00	0.00	0.04	0.00	0.00	1.64	0.25
Emergent	Distribution Pipe	Pine St E (MORATORIUM UNTIL 2025)-Ganonoque-1265	30434	Value Driven	-	-	(765)	(827)	62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.17	0.00	0.00	0.00	0.11	0.00	0.00	1.87	0.27
Existing Investment	Distribution Pipe	Spruce St-Kapuskasing-1565	30160	Value Driven	-	-	(1,728)	(1,776)	48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.54	0.00	0.00	0.00	0.07	0.00	0.00	3.92	0.56
Existing Investment	Distribution Pipe	Colborne St W 1 - Northeast - 1682	30200	Value Driven	-	-	(621)	(635)	14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.93	0.00	0.00	0.00	0.04	0.00	0.00	1.24	0.18
Existing Investment	Distribution Pipe	Glenora Dr - Southwest - London - 1517	30298	Value Driven	-	-	(1,219)	(1,264)	46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.35	0.00	0.00	0.00	0.12	0.00	0.00	2.76	0.39
Existing Investment	Distribution Pipe	Arthur St - Cornwall - Eastern - 1727	30417	Value Driven	-	-	(1,390)	(1,449)	59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.66	0.00	0.00	0.00	0.16	0.00	0.00	5.06	0.67
Existing Investment	Distribution Pipe	Randolph Ave - Southwest - Windsor - 1334	30032	Value Driven	-	-	(1,094)	(1,157)	63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.39	0.00	0.00	0.00	0.33	0.00	0.00	4.73	0.68
Existing Investment	Distribution Pipe	Pillette Rd - Southwest - Windsor - 1320	30031	Value Driven	-	-	(1,500)	(1,598)	98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	89.98	0.00	0.00	0.00	0.19	0.00	0.00	7.24	1.01
Emergent	Distribution Pipe	Eyre St - Northeast - 1286	30204	Value Driven	-	-	(1,094)	(1,124)	30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.74	0.00	0.00	0.00	0.98	0.00	0.00	2.13	0.29
Emergent	Growth	LOND - Strathroy Industrial Park Reinforcement - Strathroy	738258	Mandatory	-	-	(1,341)	(1,341)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	WATE_375 Sligo Rd Mount Forest Reinforcement	739652	Mandatory	$ 319,900	-	(195)	(195)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	WATE - Speedvale Ave W Elmira Rd Northwest Guelph System Reinforc	501677	Mandatory	$ 335,939	-	(1,603)	(1,603)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	HAMI: Ancaster Gate Modifications	739262	Mandatory	$ 281,249	-	(111)	(111)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	HAMI: New Hannon Airport Expansion Project, Hannon, Growth	739257	Mandatory	$ 1,834,639	-	(438)	(438)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	KING: Upgrade West St DRS (27601014)	49145	Mandatory	-	$ 75,780	(136)	(136)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	HAMI: Nebo Rd Airport Expansion Project, Hannon, Growth	735963	Mandatory	$ 846,806	-	(196)	(196)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	TBAY :33-25-503 Riverdale Rd to Hwy 61 via 20th	503234	Mandatory	-	-	(668)	(668)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	GreenFirst Forest Products Hearst New Kiln	739611	Mandatory	$ 912,974	-	(401)	(401)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	KING: Loyalist Pkwy Reinforcement, Wellington	49769	Mandatory	-	-	(83)	(83)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	KING: Main St, Wellington Reinforcement	49768	Mandatory	-	-	(228)	(228)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	HAMI: Dickenson Rd Airport Expansion Project, Mount Hope, Growth	735962	Mandatory	$ 1,355,517	-	(244)	(244)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	WATE- Kennedy Road, Breslau, Reinforcement	738492	Mandatory	$ 56,553	-	(35)	(35)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	LOND - Beards Lane Re-inforcement - Woodstock	739351	Mandatory	-	$ 1,060,916	(739)	(739)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	WATE_7321 Line 86 Woolwich Twp Reinforcement	738983	Mandatory	$ 177,994	-	(109)	(109)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	WATE- Pinebush Road System Reinforcement- Cambridge	738981	Mandatory	-	-	(325)	(325)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	King: Brighton Reinforcement	734744	Mandatory	-	-	(1,173)	(1,173)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	28106010 York ST and Pitt St PRS Rebuild- Picton	739857	Mandatory	$ 234,376	-	(140)	(140)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	HAMI: Caledonia North Reinforcement, Haldimand	739185	Mandatory	$ 515,651	$ 1,540,854	(1,477)	(1,477)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	BRAN- 8th Concession Road, Burford, Reinforcement	740081	Mandatory	-	$ 376,373	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	KING: Upgrade Dundas & CR2 PRS (28801009)	49097	Mandatory	-	-	(122)	(122)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	BRAN- Old Highway 24, Waterford, System Reinforcement	740082	Mandatory	-	$ 1,227,631	(869)	(869)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	BRAN- Shellard Lane, Brantford, Reinforcement	739483	Mandatory	$ 508,811	-	(381)	(381)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	SUDB: Station 43203020 New Sudbury Mall Reinforcement	503342	Mandatory	$ 255,770	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Growth	22-22-719 KING: Colborne TBS Line heater (27401001) replacement	738842	Mandatory	$ 195,593	-	(121)	(121)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	LNG	Hagar LNG Tank Boil Off Gas Recovery System	502916	Value Driven	-	-	(1,537)	(7,006)	5,469	0.00	0.00	0.00	0.00	0.00	5,469.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	LNG	Hagar Pipeduct Refurbishment	735291	Value Driven	$ 80,067	-	2,442	(134)	2,576	0.00	0.00	0.00	2,575.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	LNG	Hagar Cold Box	48714	Value Driven	-	-	(4,828)	(5,410)	582	0.00	0.00	0.00	0.00	0.00	0.00	581.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	LNG	Hagar MCC Building - Upgrades	735293	Value Driven	-	-	(117)	(124)	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.59	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.02
Existing Investment	LNG	Hagar Site Drainage Improvements	49911	Value Driven	-	$ 189,449	(353)	(354)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.42	0.00	0.00
Existing Investment	LNG	Hagar KVGR and Cycle Mix Cooler	48709	Value Driven	-	-	(14,443)	(14,973)	529	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.77	0.00	0.00	0.00	0.00	0.00	527.18	0.00	0.47
Existing Investment	LNG	Hagar JVG Compressor Upgrade	49955	Value Driven	-	-	(12,100)	(12,629)	529	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.77	0.00	0.00	0.00	0.00	0.00	527.18	0.00	0.47
Emergent	LNG	Hagar Desication Skid	49967	Value Driven	-	-	(670)	(670)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	LNG	Hagar Obsolete Instrumentation-Replace	736939	Value Driven	-	-	(431)	(431)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	LNG	Hagar Obsolete Electrical-Replace	736938	Value Driven	-	-	(431)	(431)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	LNG	Hagar Obsolete Mechanical - Replace	736935	Value Driven	-	-	(354)	(354)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	Brantford Regional Operations Centre	100665	Value Driven	$ 169,837	$ 833,577	(4,079)	(4,079)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	Simcoe Operations Centre	100674	Value Driven	-	-	610	(2,326)	2,936	0.00	0.00	0.00	0.00	2,907.20	3.97	0.00	0.00	0.00	24.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Real Estate & Workplace Services	Brantford Office Reconfiguration	739595	Value Driven	$ 60,656	-	(121)	(121)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	New London Site	101136	Value Driven	-	-	14,863	(30,911)	45,774	0.00	0.00	0.00	0.00	33,927.21	272.94	0.00	0.00	11,182.01	391.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	Hamilton Facility Decommissioning	48609	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	Sudbury Regional Operations Centre	100709	Value Driven	-	-	3,692	(6,613)	10,306	0.00	0.00	0.00	0.00	7,147.44	122.63	0.00	0.00	2,929.71	105.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Real Estate & Workplace Services	Operations Centre Retirement No. 2	100670	Value Driven	-	$ 315,749	(224)	(224)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	Thunder Bay Regional Operations Centre	100607	Value Driven	-	$ 757,797	(49)	(5,007)	4,958	0.00	0.00	0.00	0.00	4,957.81	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	Pritchard Rd. Operations Centre	100631	Value Driven	-	-	143	0	143	0.00	0.00	0.00	0.00	143.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	Ancaster Operations Centre	100664	Value Driven	-	-	(960)	(3,760)	2,800	0.00	0.00	0.00	0.00	2,832.46	(4.56)	0.00	0.00	0.00	(28.00)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Real Estate & Workplace Services	Thunder Bay Office Reconfiguration	739594	Value Driven	$ 60,656	-	(121)	(121)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Real Estate & Workplace Services	Waterloo Office Reconfiguration	739593	Value Driven	$ 60,656	-	(459)	(459)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	Operations Centre Retirement No. 4	100675	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	Woodstock Operations Centre	100680	Value Driven	-	-	23	(681)	703	0.00	0.00	0.00	0.00	703.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Real Estate & Workplace Services	London Office Reconfiguration	739592	Value Driven	$ 60,656	-	(435)	(435)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	Burlington Operations Centre	100666	Value Driven	-	-	(2,050)	(2,050)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	Union Rate Zones Micro Operations Sites Program	102392	Value Driven	$ 121,312	$ 315,749	24,665	(3,654)	28,319	0.00	0.00	0.00	0.00	28,318.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	50 Keil Renovations - Phase 5	100774	Value Driven	-	-	(1,277)	(3,747)	2,470	0.00	0.00	0.00	0.00	2,469.59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	Dawn Administrative Centre	100621	Value Driven	-	-	(6,576)	(8,596)	2,020	0.00	0.00	0.00	0.00	2,020.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	50 Keil Renovations - Phase 6	100775	Value Driven	-	-	(1,224)	(3,891)	2,667	0.00	0.00	0.00	0.00	2,667.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	555 Riverview Regional Operations Centre	100620	Value Driven	-	-	(2,463)	(5,017)	2,554	0.00	0.00	0.00	0.00	2,553.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	Leamington Operations Centre	100669	Value Driven	-	-	276	(1,620)	1,896	0.00	0.00	0.00	0.00	1,896.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	50 Keil Renovations - Phase 4	100773	Value Driven	-	-	(1,224)	(3,891)	2,667	0.00	0.00	0.00	0.00	2,667.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	North Bay Regional Operations Centre	100697	Value Driven	-	-	(1,194)	(5,314)	4,119	0.00	0.00	0.00	0.00	4,077.81	5.81	0.00	0.00	0.00	35.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	Owen Sound Operations Centre	100671	Value Driven	-	-	(713)	(1,278)	565	0.00	0.00	0.00	0.00	564.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Real Estate & Workplace Services	Timmins Operations Centre	100616	Value Driven	-	-	(385)	(907)	522	0.00	0.00	0.00	0.00	521.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Autosol Upgrade 2022	102066	Value Driven	$ -	$ -	42	0	42	0.00	0.00	0.00	0.00	41.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	UG - Customer Data Analytics Solutions (2025)	102341	Value Driven	-	-	147	(298)	445	0.00	0.00	0.00	0.00	444.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Forecaster & eWeather Upgrades 2026	735347	Value Driven	-	-	260	(383)	643	0.00	0.00	0.00	0.00	642.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	TIS	Sendout Replacement 2024	740275	Value Driven	-	$ 189,449	91	(134)	225	0.00	0.00	0.00	0.00	224.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	Call/Voice Analytics 2023	102302	Value Driven	-	-	721	0	721	0.00	0.00	0.00	0.00	720.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	TIS	Enterprise Contact Center	102304	Value Driven	$ 60,652	$ 2,392,105	1,519	(2,086)	3,604	0.00	0.00	0.00	0.00	3,604.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Real Estate & Workplace Services	GTA West - New Build - Halton Hills	739715	Value Driven	$ 500,000	-	8,793	(28,856)	37,648	0.00	0.00	0.00	0.00	29,790.16	83.12	0.00	0.00	7,694.04	81.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Pipe	A60: Scala Isolation Valves	738856	Value Driven	$ -	$ -	(25)	(25)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	Hydrogen Blending Phase 2	736974	Value Driven	-	$ 1,920,837	(5,802)	(5,802)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	2025 - SAP Product and System Refreshes	736941	Mandatory	-	-	2,036	(4,139)	6,176	0.00	0.00	0.00	0.00	6,175.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	WIND: 06E-502 Stoney Point 3100 Comber Side Rd	736331	Value Driven	$ -	$ -	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	CHAT: 08F-601 Dover Center Transmission Gravel Replacement	736290	Value Driven	$ -	$ -	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Compression Stations	SM:SCADA-Annual Upgrade 2024	9064	Mandatory	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

2024 Budget & LRP	AMP Asset Class	Investment Name	Investment Code	Planning Group	2023F	2024F	Value Score - Value Units - All Years - Current June 2023	Total Investment Cost - Value Units - All Years - Current June 2023	Total Investment Value Net of Cost - Value Units - All Years - Current June 2023	Budget Savings CAPEX (CA) - All Years - Current June 2023	Budget Savings OPEX (CA) - All Years - Current June 2023	Revenue Impact (CA) - All Years - Current June 2023	Cost Avoidance CAPEX (CA) - All Years - Current June 2023	Cost Avoidance OPEX (CA) - All Years - Current June 2023	Avoided GHG Emissions (CA) - All Years - Current June 2023	Avoided Reactive Replacement - All Years - Current June 2023	Employee And Contractor Safety Risk - All Years - Current June 2023	Employee Productivity (CA) - All Years - Current June 2023	Energy Efficiency (CA) - All Years - Current June 2023	Environmental Risk And Remediation - All Years - Current June 2023	Financial Risk - All Years - Current June 2023	Gas Storage Reliability (CA) - All Years - Current June 2023	Installation Gross Margin Impact (CA) - All Years - Current June 2023	IT And Facilities Capacity Risk - All Years - Current June 2023	Operational Disruption Risk (Gas) (CA) - All Years - Current June 2023	Operational Disruption Risk (Liquids) (CA) - All Years - Current June 2023	Operational Risk - All Years - Current June 2023	Public Safety Risk - All Years - Current June 2023	Reputational Risk - All Years - Current June 2023
No Longer in Plan	Compression Stations	SCOR:Unit Pre-Heat-Convrt	12863	Mandatory	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Compression Stations	SCOR:622xx Unit Vlv-Heat Trace	12985	Mandatory	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Compression Stations	SCOR:352 Gas Detectrs-Replace	12993	Mandatory	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergent	Distribution Stations	A10: Yonge and Steeles Feeder Station Relocation	739412	Value Driven	$ 64,899	-	234	(24)	258	0.00	0.00	0.00	0.00	55.53	0.00	0.00	0.00	0.00	0.00	0.00	202.59	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00
No Longer in Plan	Distribution Pipe	NPS 42 GTA Transmission - Integrity Retrofit > 30% SMYS	102204	Compliance	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	Alamosa Dr & Finch Ave E	1638	Mandatory	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	VSM - Major Mackenzie and Yonge	7666	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	MISSISSAUGA RD & HWY. #7 DISTRICT	18625	Mandatory	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	2031 Building Systems Blanket	736994	Mandatory	-	-	(33)	(1,182)	1,148	0.00	0.00	0.00	0.00	1,148.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	2031 LEG Rate Zone Targeted GHG & Energy Reductions	737022	Mandatory	-	-	90	(183)	273	0.00	0.00	0.00	0.00	272.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	2031 Furniture & Ergonomics Blanket	737021	Mandatory	-	-	56,110	(134)	56,244	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48,604.10	7,639.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	Kelfield Operations Centre - New Building	737226	Value Driven	-	-	2,522	(15,227)	17,749	0.00	0.00	0.00	0.00	15,958.46	49.78	0.00	0.00	1,684.89	55.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	SARN: 13O-402 Westmount Gate	734684	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	HAMI: Jarvis trans, full rebuild	735043	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	LOND: 14O-510R Curry and Oxford	734681	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	NE: 45103001 - Airport Rd TBS and DRS, Boiler Replacement	502660	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	Bay St. Roof top piping blocking Replacement and Maintenance, SSM	49670	Mandatory	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	Laird Ave - Southwest - Windsor - 1371	30021	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	County Road 46 - Southwest - Windsor - 1352	30008	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	Callie Ave - Southwest - Windsor - 1377	30007	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	Cabana Rd W - Southwest - Windsor - 1353	30006	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	Belle River Rd - Southwest - Windsor - 1366	30004	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	Base Line 2 - Southwest - Windsor - 1347	30003	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	Base Line - Southwest - Windsor - 1623	30002	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	St Anne Blvd - Southwest - Windsor - 1319	30038	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	Hydrogen for Compression Facilities Feasibility Assessment	736973	Value Driven	-	$ 757,797	(1,123)	(1,123)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	Hydrogen Fuel Heating Systems Feasibility Assessment	736972	Value Driven	-	$ 1,073,546	(1,598)	(1,598)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	2031 Furniture & Ergonomics Blanket	737020	Mandatory	-	-	56,110	(134)	56,244	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48,604.10	7,639.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	2031 Cabling	737024	Mandatory	-	-	(8)	(65)	57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	2031 LUG Rate Zone Targeted GHG & Energy Reductions	737023	Mandatory	-	-	90	(183)	273	0.00	0.00	0.00	0.00	272.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	2031 South Building Systems Blanket	737027	Mandatory	-	-	(143)	(1,232)	1,089	0.00	0.00	0.00	0.00	1,088.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Real Estate & Workplace Services	2031 North Building Systems Blanket	737025	Mandatory	-	-	(98)	(843)	745	0.00	0.00	0.00	0.00	744.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	TIS	BODS Upgrade 2029	101108	Value Driven	-	-	195	(85)	280	0.00	0.00	0.00	0.00	280.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Pipe	HAMI: Conc 3/Walpole Rd, Walpole, BU Replacement	733627	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	50356A COUNTY RD #55 HWY #9 DISTRICT (NEW TECUSETH)	735309	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	61061A PEMBROKE W. DISTRICT	735167	Value Driven	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
No Longer in Plan	Distribution Stations	HAMI - Six Nations	101098	Mandatory	-	-	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	A30: Interchange Way Reinf	736389	Mandatory	$51,348	$615,308	(463)	(463)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	Brockville Gate Extension	102119	Mandatory	-	$327,083	(2,050)	(2,050)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	Erin IP System Reinforcement	16748	Mandatory	-	-	3,635	(3,040)	6,675	0.00	0.00	6,674.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	Huntmar Drive Reinforcement	501824	Mandatory	$1,467	-	(3,075)	(3,075)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	King - Chesterville, Crysler, Finch Reinforcement	100778	Mandatory	$379,689	-	(235)	(235)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	NBAY: Upgrade Maplewood PRS (43801127)	49164	Mandatory	$15,013	-	(9)	(9)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	NW 6581 Ottawa Reinforcement Phase 2 SRP	1024	Mandatory	-	-	(17,462)	(32,787)	15,325	0.00	(20,840.24)	36,165.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	Rodinea Road	2522	Mandatory	$7,335	-	(5)	(5)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	SRP_GTA West_Lowville_18X-101STN_Rebuild	735034	Mandatory	-	$884,097	(263)	(626)	363	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	356.21	0.00	0.00	0.00	0.00	6.67	0.00	0.00
Existing Investment	Growth	SRP_Southwest_Kerwood_12K-301STN_Rebuild	734672	Mandatory	$234,376	$6,504,425	(7,736)	(7,787)	51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	6.59	0.00	0.00	0.00	0.00	0.00	44.26	0.00	0.38
Existing Investment	Growth	THUN: Rosslyn Rd at Sideroad 20 Reinforcement Project	734531	Mandatory	-	-	(104)	(104)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	TIMM 45-21-501 St Jean @ Shirley NPS4 Reinforcement - Timmins	502816	Mandatory	-	-	(42)	(42)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	TIMM 45-22-502 Shirley St @ Riverside Rd NPS4 Reinforcement - Timmi	502817	Mandatory	-	-	(65)	(65)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	TIMM: West Timmins System Reinforcement (McBride North and Shirle	100936	Mandatory	-	$197,974	(789)	(789)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Existing Investment	Growth	WATE: 21U-101 Fergus Second Stage, Fergus, Station Rebuild (Load Gro	100831	Mandatory	-	$378,899	(648)	(1,026)	377	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.16	362.30	0.00	0.00	0.00	0.00	0.00	3.60	0.00	2.31
Existing Investment	Growth	WATE: Listowel System Reinforcement, Proj# 07-21-705	49794	Mandatory	$468,752	$442,048	(603)	(603)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Greenhouse Vegetable Growers (OGVG)

Undertaking

Tr: 44

For the table at exhibit JT5.13, attachment 1 to add two columns to the table showing forecast spending for projects for 2023 and 2024.

Response:

Please refer to Exhibit J14.6 Attachment 1.

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 105

To provide current membership of Enbridge Gas executive management committee

Response:

Enbridge Gas interprets the undertaking to be asking for the current membership of the Enbridge Inc. Capital Allocation Committee (CAC) per Tr. Vol.14 105.

The current members of the CAC are:

- Senior Vice President, Corporate Development
- Chief Financial Officer (CFO)
- Chief Legal Officer (CLO)
- Executive Vice President, Strategy
- Vice President, Treasury

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 116

To file a copy of Enbridge's risk register, according to confidentiality protocols.

Response:

Please find the GDS Risk Register included in Attachment 1. As stated in Exhibit 2, Tab 6, Schedule 2, page 50, the Risk Management process focuses on "operational hazard and risk identification." These are operational risks that are primarily related to operational safety and reliability. Please note this register includes risks to all GDS businesses.

During the hearing Enbridge Gas indicated that it utilizes a broad range of methods to treat risk.[1] As outlined in the AMP[2] and demonstrated by the attached GDS Risk Register, quantitative, semi-quantitative and qualitative methods are used to establish risk, including the likelihood and impact of each event. Quantitative risk evaluation methods require significant amounts of data whereas semi-quantitative and qualitative risk evaluation methods can be conducted using tacit knowledge.

During the hearing, there were also questions posed to Enbridge Gas about what efforts the company has taken to establish the risks associated with energy transition, including the probability and impact[3]. As noted in Ms. Wade's testimony, energy transition is considered and factored into the company's demand forecast process, at both the system and local level. This process is evolving and includes monitoring of the customer count, average use, design day and design hour demand forecasts. Where known or strong signals exist, energy transition adjustments are included in the forecasts in a binary approach, and this effectively assigns the adjustments a probability of 1 (or certain to materialize). This deterministic approach balances known or strong signals with less certain indicators, which are not included in the forecast – effectively giving the latter indicators a probability of 0. The energy transition adjustments that have been included, are described in Exhibit 1 Tab 10 Schedule 4, pages 4, 6, 9-12, Exhibit I.1.10-

[1] Tr. Vol 13, pp.176-177.
[2] Exhibit 2, Tab 6, Schedule 2, p. 50, Table 4.2-1
[3] Tr Vol. 14, pp. 112-113.

STAFF-31, and Exhibit 1.1.10-SEC-23. Although probabilities were not assigned to the adjustments included, the impact of different assumptions were modeled in the Posterity Energy Transition Scenario Analysis work, which provides an understanding of how different assumptions could impact Enbridge Gas's annual and peak volumes.

This deterministic approach to the likelihood and impact of energy transition factors is different than the likelihood and impact ranking approach used by Enbridge Gas in its operational risk assessment. To develop a probabilistic and impact ranking approach for energy transition related factors, Enbridge Gas would need to establish a list of all the factors that could change the need for the gas system and then acquire information to establish both the likelihood of these factors occurring and the degree of adjustment, required. This information does not currently exist, and it is doubtful that the probabilistic approach could be developed now given that most critical drivers are policy driven or are related to disruptive changes in technology. In the absence of requisite information, establishing probabilities would require a qualitative approach. This would not be appropriate, as the qualitative information used would not be based on tacit knowledge or experience; instead, it would be based upon stakeholders' own forward-looking perspective of which pathway should come to fruition, resulting in an inherently biased and/or highly debatable set of probabilities. As such, coming to an agreed upon set of probabilities at this time would be difficult, if not impossible, and Enbridge Gas believes this time-intensive process would not be of value in an ever-changing energy-transition environment absent clearer signals related to policy and technologies.

It is important to note that although some may point to pathways studies that have been conducted as a dataset that could be relied upon to create a probabilistic and impact ranking approach, these studies have defined scenario outcomes with predefined assumptions. Therefore, using them to determine the probability of a factor occurring or the associated impact would not be appropriate. Further, as noted by Ms. Wade in discussion with Mr. Daube[4], the assignment of probabilities to scenario analyses becomes inherently more theoretical as the number of unknowns (i.e., critical drivers, potential policy outcomes, costs, etc.) increase over a longer time period.

[4] Tr. Vol. 4, p. 71, line 5.

First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version	Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution											5	LUG	FINAL	1	Construction damage to stations while doing rework	Neil MacNeil	Construction damage to stations while doing rework	2nd party damage
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution											17	LUG	FINAL	2	Improper commissioning / station start-up - ruining valves, equipment	Murray Costello	Improper commissioning / station start-up - ruining valves, equipment	Incorrect operation
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution											63	LUG	FINAL	3	Initial inspection for new customers	Steve McGivery	During "initial putting into use" inspection, deficiencies could be overlooked that could lead to an unacceptable situation. Initial inspection emphasis is on installation compliance with code given that equipment has not yet seen complete seasons of operation, and the installation environment has not yet experienced changes at the hands of the premises owner. This would not involve Union Gas Assets, but could lead to regulatory, reputation and/or financial consequences. Examples of items that could be overlooked are: -Proper vent sizing; proper pipe sizing; safe operation of new technology gas-fired equipment. Examples of unacceptable conditions are: -CO production due to incorrect venting; incorrectly sized piping causing equipment shutdown; improper installation clearances causing heat damage to combustibles; improper support of equipment and ancillary components allowing movement	Inspection deficiency
1. Natural gas distribution	1.3. Customer asset	1.3.3. Customer Asset Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate										64	LUG	FINAL	4	Re-inspection of existing customers	Steve McGivery	During periodic re-inspection, deficiencies could be overlooked that could lead to an unacceptable situation. Re-inspection emphasis is on gas-fired equipment and ancillary component operating condition, and changes made to the installation environment by the premises owner or user. This would not be on Union Gas Assets, but could lead to regulatory, financial and/or reputation consequences. Examples of dangerous situations are; - CO production due to fouling & spillage (including natural draft fireplaces) - Explosion due to failure of safety (e.g. boiler safety deteriorated or disconnected over time) -Fire after distributor inspection due to code criteria not being met such as clearance to combustibles changing over time (e.g. due to finishing of basements)	Inspection deficiency
1. Natural gas distribution	1.3. Customer asset	1.3.3. Customer Asset Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									66	LUG	FINAL	5	Customer operating before initial inspection	Tracey Teed Martin	Unauthorized activation of "initial putting into use" appliances before initial inspection. This is a situation made possible by providing gas service for construction heat. This would not be on EGI assets, but could lead to regulatory, reputation and/or financial consequences. Examples of unacceptable conditions are: - Furnaces activated for con heat but not following authorization form posting process - Water heaters activated for construction clean-up - Other appliances activated during painting and flooring installation by third parties	Incorrect operation
1. Natural gas distribution	1.3. Customer asset	1.3.3. Customer Asset Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									51	LUG	FINAL	7	Low voltage (750 volts or less) energization of plant pipe from customers with back-up generators.	Steve McGivery	Three conditions have to occur. There must be a fault, the ground system must not be effective and a person has to be doing work. A fault typically lasts for about 1/2 of a second. In addition, the ESA has denoted this not to be a risk.	Electrical/controls malfunction
1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution	1.14. EGI Aggregate										65	LUG	FINAL	10	Data accuracy for station assets	Andrew Welburn	Data accuracy has become a concern within SAP PM. A number of issues have contributed to this issue: free form equipment data entry, missing and inaccurate station equipment information, and missing station valves as examples. These issues contribute to missing inspection records (valves in particular), as well as inaccurate station capacity assessments and overall unreliable station records in SAP.	Missing, incorrect or incomplete records
1. Natural gas distribution	1.3. Customer asset	1.3.2. Residential Meter	1. Ontario Distribution	1.14. EGI Aggregate										6	LUG	FINAL	11	Physical impact of meter sets specifically at high traffic areas	Steve McGivery	Physical impact to meter sets	3rd party damage
1. Natural gas distribution	1.3. Customer asset	1.3.2. Residential Meter	1. Ontario Distribution	1.14. EGI Aggregate										11	LGD	FINAL	12	Inside Meter defects	Tracey Teed Martin	Defects in meters supplying to company could be used / installed in the network without detection leading to pre-mature failures. This could lead to service disruption, increase green house gas emission and increase cost due to investigation and repairs / replacements	Manufacturing defects
1. Natural gas distribution	1.3. Customer asset	1.3.2. Residential Meter	1. Ontario Distribution	1.14. EGI Aggregate										12	LGD	FINAL	13	Inaccurate metering of natural gas	Carrie Cook	Malfunction of gas meters would lead to inaccurate measurement of natural gas usage.	Equipment malfunction
1. Natural gas distribution	1.3. Customer asset	1.3.3. Customer Asset Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										N/A - New after merge	EGI	FINAL	15	Unsealed meter boxes	Carrie Cook	Unsealed meter boxes and corroded meter boxes pose a potential gas migration path into the customer premise	Construction defect
1. Natural gas distribution	1.3. Customer asset	1.3.2. Residential Meter	1. Ontario Distribution	1.14. EGI Aggregate										34	LGD	FINAL	16	Snow/ice damage to meter sets	Carrie Cook	Damage of meter sets due to falling snow / ice shedding from roof tops	Natural forces/weather
1. Natural gas distribution	1.3. Customer asset	1.3.2. Residential Meter	1. Ontario Distribution	1.4. Toronto (Area 10)	1.4.1. 10 – Toronto	New 2019	LGD	Final	17					New 2019	LGD	Final	17	Ambiguity in Responsibility for Regulatory Safety Function for Gas Sub-Metering by Others	Tracey Teed Martin	Gas sub-metering by others may create ambiguity about who is responsible for important regulatory safety functions related to the gas piping systems and end users of gas appliances installed within building complexes. This could lead to unintended lapses that may cause public safety risks.	Inspection deficiency
1. Natural gas distribution	1.3. Customer asset	1.3.2. Residential Meter	1. Ontario Distribution	1.14. EGI Aggregate										9	LUG	FINAL	18	[redacted]	Steve McGivery	[redacted]	
1. Natural gas distribution	1.3. Customer asset	1.3.2. Residential Meter	1. Ontario Distribution	1.14. EGI Aggregate										10	LUG	FINAL	19	Customer alteration of company assets at meter set	Steve McGivery	Home owner activity - painting over reg vents, roofing material on meter sets, damage to vent lines, decks added causing splash issue or over reg, snow clearing	3rd party damage
1. Natural gas distribution	1.1. Pipe	1.1.4. Valve	1. Ontario Distribution	1.14. EGI Aggregate										21	LUG	FINAL	20	Buried stops could hinder emergency response	Steve McGivery	Buried stops in concrete and asphalt or any substance that could not be readily excavated by hand in an emergency. Does not allow Emergency crews to readily shut off gas in case of emergency	Construction defect
1. Natural gas distribution	1.3. Customer asset	1.3.3. Customer Asset Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									30	LUG	FINAL	21	Wall piece deterioration	Steve McGivery	Wall piece deterioration and disturbance during meter change or homeowner activity. Buried and above grade wall pieces that are disturbed could cause a leak inside the wall.	Equipment malfunction
1. Natural gas distribution	1.1. Pipe	1.1.3. Gas Service	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate	33	LUG	DRAFT	22	Service Regulator malfunction	TBD	Loss of pressure control and overpressure protection due to malfunction of service regulator.	Equipment malfunction	33	LUG	FINAL	22	Service Regulator malfunction	Steve McGivery	Loss of pressure control and overpressure protection due to malfunction of service regulator.	Equipment malfunction
1. Natural gas distribution	1.3. Customer asset	1.3.3. Customer Asset Aggregate	1. Ontario Distribution	1.9. Legacy UGL Aggregate	1.9.1. Aggregate									16	LUG	FINAL	23	Internal corrosion impacting regulator function	Tara Kuuskman	Internal corrosion resulting in equipment malfunction due to corrosion by-products impairing functionality. This risk refers to the Byron Donkin Regulator.	Corrosion internal
1. Natural gas distribution	1.2. Station	1.2.1. Customer Station	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate	20	LUG	DRAFT	25	Inadequate OPP at commercial/industrial customer stations	TBD	Some customer stations have potentially inadequate overpressure protection.	Construction defect	20	LUG	FINAL	25	Inadequate OPP at commercial/industrial customer stations	Murray Costello	Some customer stations have potentially inadequate overpressure protection.	Construction defect
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										11	LUG	FINAL	28	Station corrosion under insulation	Tara Kuuskman	Degrading asset health due to potential piping corrosion under insulation or at building penetration on the inlet piping of a station	corrosion external
1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution	1.14. EGI Aggregate										107	LGD	FINAL	30	[redacted]	Murray Costello	[redacted]	
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										108	LGD	FINAL	31		Steve McGivery		
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										109	LGD	FINAL	32		Steve McGivery		
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										4	LUG	FINAL	35	Vehicle hit on small distribution stations near road	Murray Costello	Vehicle hit on small distribution stations near road	3rd party damage

Current ID	Source	Consequences	Controls	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
1	Construction damage to stations while doing rework	Potential impact to operation and worker/public H&S	- Some inspection - Sercon process - Procedures of work - Locates	Prevent, Detect Prevent Prevent Prevent	Public safety	Financial	5	3							One RR only	MP-01: Asset	7/4/2022
2	Improper commissioning / station start-up - ruining valves, equipment	Potential impact to operation	- Procedures of work - Engineering practices - DOM station commissioning process - Technician valve training	Prevent Prevent Prevent, Detect Prevent	Operational reliability	Financial	5	2							One RR only	MP-01: Asset	2021-06-29
3	During "initial putting into use" inspection, deficiencies could be overlooked that could lead to an unacceptable situation. Initial inspection emphasis is on installation compliance with code given that equipment has not yet seen complete seasons of operation, and the installation environment has not yet experienced changes at the hands of the premises owner. This would not involve Union Gas Assets, but could lead to regulatory, reputation and/or financial consequences. Examples of items that could be overlooked are: -Proper vent sizing; proper pipe sizing; safe operation of new technology gas-fired equipment. Examples of unacceptable conditions are: -CO production due to incorrect venting; incorrectly sized piping causing equipment shutdown; improper installation clearances causing heat damage to combustibles; improper support of equipment and ancillary components allowing movement	Lead to potential regulatory, reputation and/or financial consequences.	- Codes, standards & regulations - SOP - System-triggered inspection process & procedures - Training on inspection procedures - Infraction tag process - Delayed inspection warning procedure - Ontario Law requiring CO alarms in all residential premises (new build and existing buildings) - Ongoing QA audits and CAP audits	Prevent Prevent, Detect Detect Prevent Detect Detect Prevent	Operational regulation	Reputational	1	4							One RR only	MP-01: Asset	7/4/2022
4	During periodic re-inspection, deficiencies could be overlooked that could lead to an unacceptable situation. Re-inspection emphasis is on gas-fired equipment and ancillary component operating condition, and changes made to the installation environment by the premises owner or user. This would not be on Union Gas Assets, but could lead to regulatory, financial and/or reputation consequences. Examples of dangerous situations are; - CO production due to fouling & spillage (including natural draft fireplaces) - Explosion due to failure of safety (e.g. boiler safety deteriorated or disconnected over time) -Fire after distributor inspection due to code criteria not being met such as clearance to combustibles changing over time (e.g. due to finishing of basements)	Lead to potential regulatory, reputation and/or financial consequences.	- Gas Technician safety advisory bulletins - SOP - QA triggered re-inspection - inspection process & procedures, training on inspection procedures - infraction tag process - public education re regular inspections (newsletter) through direct mail (bill insert) - Ontario Law requiring CO alarms in all residential premises.	Prevent Prevent Detect Detect Prevent Prevent	Operational regulation	Reputational	3	4							One RR only	MP-01: Asset	7/4/2022
5	Customer putting equipment into service prior to initial inspection without company knowledge	potential unsafe condition, regulatory non-compliance	Codes, standards & regulations "Activation for construction heat" procedure (posting of signed form) Various builder service request forms explaining appliance activation restrictions Reports from field of other trades activating uninspected appliances. QA audit of situation in field for informed decision making. More communication to builders & their trades. More reporting of "blatant disregard" cases to TSSA. Advise marketing builder & HVAC support reps to communicate the concerns.	prevent prevent prevent detect	Operational regulation	Reputational	5	4						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
7	Incorrect installation (e.g. due to human factor or issues with procedures) NOTE : Historically there were cases where 1st cut was missing	Result to inaccurate measurement of gas consumption and unreliable services. It could also post H&S concern to public.	- Grounding and bonding of customer stations - Customer maintenance and inspection of equipment - Maintenance of their equipment	Prevent Detect Prevent	Workforce safety	Health & Safety	1	4							One RR only	MP-01: Asset	7/4/2022
10	Unreliable station records in SAP (e.g. missing equipment data entry, inaccurate station equipment information, missing inspection records, inaccurate station capacity assessments)	Impacting inspection quality / frequency of assets leading to operational reliability issue	- Data issues are slowly being fixed as they are identified - Yearly capacity checks help to uncover these issues - Construction and maintenance processes are being reviewed and improved to streamline data entry and construction practices to help alleviate these concerns	Prevent Prevent Prevent	Operational reliability	Reputational	3	5			AWS Phase 3 will migrate station (non-STO) records into Maximo.			Risk Owner Updated from Shawn K to Andrew W 6/13/2023	One RR only	MP-01: Asset	2023-06-13
11	Vehicle impact to meter sets	Damage meter leading to operational reliability issue	- Procedure 18.23 C&M manual -Excess Flow Valve -Meter Barriers -Installation practice for meters prone to vehicular traffic	Prevent, Mitigate	Operational reliability	Reputational	1	3							One RR only	MP-01: Asset	44746
12	Manufacturing defects	H&S impact to public and possible worker in case of a flammable event NOTE: Ranking is based inside meter approx. 30k to 50k	- Meter, Instrument, and Regulator Replacement Program - Leak Monitoring - Leak Survey - Special Request Surveys - For asset outside annual leak survey plan - Leak Repair	Prevent Detect Detect Detect Mitigate	Public safety	Health & Safety	2	5						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	Reputational : L2C5 High	MP-05: Integrity	44732
13	Equipment failure or human error	Inaccurate measurement of natural gas usage	- Meter, Instrument, and Regulator Replacement Program - Inspections and Re-inspections of Customer Piping, Equipment and Appliances	Prevent Prevent	Operational reliability	Financial	7	1							One RR only	MP-05: Integrity	2021-06-11
15	Unsealed meter boxes could be caused by incorrect installation or caused by degradation of the meter box over time. Meter box corrosion could be influenced by landscaping/drainage of side walk salt/snow melt into meter box. The customer may not be aware that maintenance of the meter box is their responsibility (the meter box is not a Company owned asset however the Company's assets are located inside the meter box). Possible leak from any gas piping inside meter box, riser, fitting, regulator, or meter.	If leak is in inlet side of regulator (or upstream of regulator) IP leak into meter box with gas migration path into the premise leading to possible build up to LEL, possible ignition (fire or explosion), resulting in possible fatality. The IP fuzz leaks, and LP leaks would be less likely to result in the final consequence described i.e. the IP leak is the driver of risk ranking.	1. Gas is odourized for leak detection. Emergency response procedures 2. Routine visual inspections through MXGI and other service calls, leak survey. Including red tag of gas migration path into building causing potentially hazardous situation 3. Excess flow valve (EFV) on service for some premises. Will only trip closed for a certain larger size of leak 4. At installation, meter boxes should be sealed and vented to atmosphere	Detect & Mitigate Detect & Prevent Prevent Prevent	Public safety	Health & Safety	2	6						**Treatment plan moved to comments 06 23 2022** 1. Consider customer communication regarding their ownership and maintenance responsibility of the meter box. Consider training for MET, leak survey, and Lakeside to detect meter box issues and report them to the company for follow-up. Consider using MET to survey for the complete population of meter boxes for tracking in MAXIMO. The issue is the customer owns the meter box and needs to be informed how to maintain them considering corrosion and unsealed boxes that are a potential gas migration path into the premise. Consider what contractors are approved for remediation/installation, how to make repairs up to EGD standard. 2. Consider alternate meter box designs (EGD approved what designs are used however the customer owns the meter box) including plastic materials of construction, possible coating on meter box, clearance above grade (drainage issue), installation location (avoiding corrosive areas with salt). Part of the design concern is multi piece meter boxes may be harder to ensure they are sealed. Or if the building layout permits, consider relocating the meter set. Work done by records to locate meter boxes.	Financial; L4, C1, RR Low	MP-05: Integrity	2022-06-23
16	Falling snow / ice from roof tops	Damage meter leading to potential meter malfunction. There is remote chance of natural gas releases. **NOTE**: Snow fall deflected from infrastructure	- Protective structures over meter sets which are at risk of snow / ice damage - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan)	Mitigate Mitigate	Operational reliability	Financial	6	1							One RR only	MP-02: Emergency	2021-06-11
17	Gas sub-metering by others may create ambiguity about who is responsible for important regulatory safety functions related to the gas piping systems	Sub-metering sites typically serve multi-family buildings/vertical subdivisions, with greater population within a single building.	SOPs Gas Supply Standard	Prevent	Public safety	Health & Safety	1	6			Summary: Q3 2021 -Negotiations between SCO* and EGI to clarify roles/responsibilities, based on both safety and business implications -Clarity/Agreement on SCO*/EGI responsibilities will ensure that buildings with sub-metering have regulatory safety functions (i.e. re-introduction of gas and inspections) Status: Q3 2021 -The MUB gas supply and sub-metering reports have been completed and published. -Revised Gas Supply Standard Letter based on stakeholder consultation will be released in July, and training with operations and sales has been completed in Q3, 2021. -TSSA has been supplied with a list of Toronto addresses with sub-metering for them to follow up with. There is a requirement for builders to sign off that sub metering companies are fuel distributors and supply Enbridge with a copy of the license. Q4 2021 - Q1 2022 Risk treatment plan has been completed but risk has not been mitigated. Is not reported during Q1 MP-01 MR.			Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
18	[redacted]			Mitigate	Operational reliability	Reputational	3	3							One RR only	MP-06: Security	7/4/2022
19	Home owner activity - painting over reg vents, roofing material on meter sets, damage to vent lines, decks added causing splash issue or over reg, snow clearing	Impacting reliability to supply gas to customer	- Winter watch - Meter readers review (not with ERT meters) - Bill inserts - Social media notifications regarding clearing snow from your meters	Detect Detect Prevent Prevent	Operational reliability	Financial	5	2							One RR only	MP-01: Asset	7/4/2022
20	Buried stops in concrete and asphalt or any substance	Delay excavated by hand in an emergency. Does not allow Emergency crews to readily shut off gas in case of emergency	-ERP - Prioritized work identified by meter readers	Mitigate Prevent	Operational reliability	Financial	3	4							One RR only	MP-01: Asset	7/4/2022
21	Deterioration of wall piece due to exposure to natural environment, homeowner activity, meter change activity **NOTE on hazards** Other hazards would be 1st, 2nd and 3rd party damages	Potential leak inside the wall	- leak investigation SOP; - re-inspections; procedural update; - Technical Communication	Detect Prevent, Detect Prevent	Operational reliability	Operational	5	3							One RR only	MP-05: Integrity	7/4/2022
22	Equipment failure	Loss of pressure control leading to overpressure	- Regulator is replaced if meter is being replaced	Prevent	Operational reliability	Financial	1	2							One RR only	MP-05: Integrity	7/4/2022
23	internal corrosion causing regulator malfunction	corrosion resulting in regulator malfunction resulting in over or under pressure and subsequent safety risk and/or operational incident	- Regulators and OPP tested and evaluated and/or replaced if meter being changed	Detect, Prevent	Public safety	Health & Safety	1	6						Risk Owner updated from A.S on August 1, 2023		MP-05: Integrity	2021-06-25
25	Station Pressure Regulator malfunctions open or fails to lock up at station with inadequate OPP	Older customer equipment in LP system not able to cope with even a small system overpressure	- Inspections - Capital replacements - Emergency Response Program	Prevent Prevent Mitigate	Public safety	Health & Safety	3	5							One RR only	MP-01: Asset	2021-06-28
28	Potential piping corrosion under insulation or at building penetration on the inlet piping of a station.	Leading to degraded asset condition and potential leaks	- An existing program and budget to proactively locate the issues of concern. - The station painting program currently is serving to identify corrosion based on the existence of pitting	Detect Prevent	Operational reliability	Financial	5	3						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2021-06-02
30	[redacted]			Mitigate Prevent Detect Mitigate Detect , Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Operational	1	7							H&S L1, C6, RR Medium	MP-06: Security	2021-06-14
31				Mitigate Prevent Detect Mitigate Detect , Mitigate Mitigate Mitigate Mitigate	Public safety	Health & Safety	1	7						[redacted]	Operational: C2, L2, Low	MP-06: Security	10/31/2022
32				Mitigate Prevent Mitigate Mitigate	Public safety	Health & Safety	1	7							One RR only	MP-06: Security	7/4/2022
35	other outside forces (vehicle leaving roadway)	operational impact to customers and potential H&S impact to the public	- Some fenced (typically in remote locations) - Reference 18.23 in the C&M Manual - barricades for above ground facilities - Pipeline Markers	Prevent	Public safety	Financial	5	2							One RR only	MP-01: Asset	2021-06-29

First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version	Current ID
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.9. Legacy UGL Aggregate	1.9.1. Aggregate									12	LUG	FINAL	36
1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution	1.12. Legacy UGL Aggregate										13	LUG	FINAL	39
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.9. Legacy UGL Aggregate	1.9.1. Aggregate									14	LUG	FINAL	40
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.9. Legacy UGL Aggregate	1.9.1. Aggregate									15	LUG	FINAL	41
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate		18	LUG	DRAFT	42	Incorrect station construction	TBD	Improper station construction - not following drawings (changing station capacity, etc.). Potentially could lead to costs to modify station back to design or possible capacity decrease or overpressure of downstream pipeline. Applicable to Head Office designed stations and District built PFM stations.	Construction defect	18 - System Stations / All Stations (except residential)	LUG	FINAL	42
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.9. Legacy UGL Aggregate	1.9.1. Aggregate									22	LUG	FINAL	47
1. Natural gas distribution	1.2. Station	1.2.1. Customer Station	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate	N/A - New after merge	EGI	DRAFT	426	Legacy Inside Regulators at Utilization Meter Sets with Slamshut Valve (Inlet P > 2 psig)	TBD	The risk ranking driver is potential for 3rd party "pull" damage to cause the service to leak or separate at the indoor regulator inlet connection	Accidental release/LOC flammable gas due to any of the following hazards: - 1st & 2nd Party Damages - Mechanical Damage - Excavation - 1st & 2nd Party Damages - Mechanical Damage - HDD - 3rd Party Damage - Latent Damage - 3rd Party Damage - Mechanical Damage - Excavation - 3rd Path Damage - Mechanical Damage - HDD - 3rd Party Damage - Vandalism - Equipment Failure - Malfunction of Control/Overpressure Protection - External Corrosion - Atmospheric Corrosion - External Corrosion - External Metal Loss	34 - System Stations / Commercial / Industrial Stations	LUG	FINAL	48
1. Natural gas distribution	1.2. Station	1.3.3. Customer Asset Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate	N/A - New after merge	EGI	Final	427	Farm Tap / Property Line Regulator / 1st Cut Regulator with HP or XHP inlet - Equipment Failure Hazard	TBD	The 1st cut regulator could potentially malfunction open due to many different causes leading to higher than intended pressure to the 2nd cut regulator. If the 1st cut failure is severe and the 1st cut overpressure protection independently fails, it could potentially mean that the maximum emergency inlet pressure of the 2nd cut regulator is exceeded leading to potential consequences at the downstream customer. The 1st cut regulator could potentially malfunction closed or partially closed due to various causes. Resulting in a customer outage and relight.	1. Equipment Failure - Mechanical Fitting Malfunction (Pressure Reducing Regulator Fails closed / Failure to lock-up under no flow conditions) 2. Internal Corrosion - Internal Corrosion 3. Material Degradation - Damage to Regulator Cap 4. Manufacturing defect	36 - System Stations / Commercial / Industrial Stations	LUG	FINAL	49
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.9. Legacy UGL Aggregate	1.9.1. Aggregate									29	LUG	FINAL	50
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate		34	LUG	DRAFT	48	Service Regulator malfunction - diaphragm	TBD	Aging (regulator diaphragms) - increases risk of an overpressure if vent gets blocked - older regulators have less resistance to vent freezing Loss of pressure control and overpressure protection due to malfunction of service regulator.	Equipment malfunction	32 - System Stations / Commercial / Industrial Stations	LUG	FINAL	51
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.14. EGI Aggregate		36	LUG	DRAFT	49	Operating on monitor without physical indication	TBD	There are an unknown number of integrated monitor operator regulators (e.g. S200) that may not be being inspected as per SOP 7200-07. These regulators can fail and operate on monitor without any physical indication outside of an inspection. This would cause an inadequacy of overpressure protection at the station	Equipment malfunction	16	LGD	FINAL	52
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate			LUG	DRAFT	455	SCADA Misinformation	TBD	Wrong RTU load copied Example - wrong data being displayed to controller. This could be related to field tech training.	Equipment malfunction	62 - System Stations / All System Stations	LUG	FINAL	58
1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution											17	LGD	FINAL	60
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate	40	LUG	DRAFT	63	Odourant over odorization - PROPOSED COMBINED RISK		Proposed: Murray Costello	Over odourization of gas in distribution system or release of odourized gas into atmosphere.	40	LUG	FINAL	63
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											23	LUG	FINAL	67
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											25	LUG	FINAL	68
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution											26	LUG	FINAL	69
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate										28 - System Stations / Vaulted Stations	LUG	FINAL	70
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution											27	LUG	FINAL	71
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	2. Ontario Transportation	1.11. EGI Aggregate	1.11.1. EGI Aggregate									New 2019	EGI	FINAL	72
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution											37	LUG	FINAL	76
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution											42	LUG	FINAL	78
3. Aggregate	1.2. Station	1.2.3. Station Aggregate	3. Aggregate											43	LUG	FINAL	79
1. Natural gas distribution	1.2. Station	1.2.1. Customer Station	1. Ontario Distribution	1.14. EGI Aggregate										44	LUG	FINAL	80
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										45	LUG	FINAL	81
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											47	LUG	FINAL	82
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									46	LUG	FINAL	83
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									50	LUG	FINAL	85
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									52	LUG	FINAL	86
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									53	LUG	FINAL	87
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									54	LUG	FINAL	88
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									55	LUG	FINAL	89
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									57	LUG	FINAL	91

Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard	Source	Consequences	Controls
36	Corrosion underneath insulation	Tara Kuuskman	Potential piping corrosion under insulation or at building penetration on anything downstream of the inlet piping.	Corrosion external	Corrosion under insulation at building penetration on anything downstream of the inlet piping	Degrade of asset condition and potential for leaks	- An existing program and budget to proactively locate the issues of concern. - The station painting program currently is serving to identify corrosion based on the existence of pitting.
39	Relief valve corrosion at system stations	Tara Kuuskman	Corrosion/deterioration of relief valve internals such that it passes SOP testing but emergency operation is impaired leading to overpressure.	Corrosion internal	Corrosion of relief valve internals	Relief valve may pass SOP testing however may not function as intended during an emergency i.e. pressure regulator malfunctions open. Resulting in possible overpressure	Condition of assets are monitored and inspected on a routine basis and replaced as required.
40	Internal corrosion of buried station assets	Tara Kuuskman	Internal corrosion leading to leak and rupture	Corrosion internal	Internal Corrosion of buried station piping due to various causes	potential for leaks	-Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, and ERP (Emergency Response Plan) - Spot inspections when available - Investigative digs - ERP
41	External corrosion of buried station assets	Tara Kuuskman	External corrosion leading to leak and rupture	Corrosion external	External Corrosion of buried pipe in stations caused by multiple sources	potential leak of buried piping	- Corrosion control program (leak survey, coating, cathodic, callout) - spot survey - investigative digs -Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, and ERP [@[Control Category]](Emergency Response Plan)
42	Incorrect station construction	Neil MacNeil	Improper station construction - not following drawings (changing station capacity, etc.). Potentially could lead to costs to modify station back to design or possible capacity decrease or overpressure of downstream pipeline. Applicable to Head Office designed stations and District built PFM stations.	Construction defect	Not following drawings in constructing station	Potentially could lead to costs to modify station back to design or possible capacity decrease or overpressure of downstream pipeline.	- Site inspections - C&M documents to ask engineering for changes as-building
47	Debris on regulator seat	Tracey Teed Martin	Some Monitor Operator installations at distribution stations and customer stations without filtration upstream are potentially subject to failure.	Equipment malfunction	debris entering regulator due to lack of upstream filtration	debris resulting in regulator malfunction resulting in over or under pressure and subsequent safety risk and/or operational incident	- Periodic capacity checks - Capital replacements
48	Service Regulator malfunction - diaphragm	Murray Costello	Aging (regulator diaphragms) - increases risk of an overpressure if vent gets blocked - older regulators have less resistance to vent freezing Loss of pressure control and overpressure protection due to malfunction of service regulator.	Equipment malfunction	Service Pressure Regulator malfunctions open or fails to lock up	Potential for overpressure of downstream assets	- Residential regulators replaced if meter being replaced
49	Operating on monitor without physical indication	Steve McGivery	There are an unknown number of integrated monitor operator regulators (e.g. S200) that may not be being inspected as per SOP 7200-07. These regulators can fail and operate on monitor without any physical indication outside of an inspection. This would cause an inadequacy of overpressure protection at the station	Equipment malfunction	There are an unknown number of integrated monitor operator regulators (e.g. S200) that may not be being inspected as per SOP 7200-07.	These regulators can fail and operate on monitor without any physical indication outside of an inspection. This would cause an inadequacy of overpressure protection at the station	Regular inspections Regular maintenance
50	Inadequate over pressure protection (distribution station).	Murray Costello	Some distribution stations have potentially inadequate overpressure protection.	Construction defect	Station Pressure Regulator malfunctions open or fails to lock up at station with inadequate OPP	Potential over-pressure of downstream system	Periodic capacity checks - Inspections - Capital replacements - Emergency Response Program
51	External relief valve not installed at station with IMRV regulator	Steve McGivery	External relief not added to IMRV regulators - failure will lead to overpressure of customer piping	Installation error	Pressure regulator malfunctions open or fails to lock up	Pressure increase leading to possible overpressure if IMRV regulator failure is catastrophic and there is also no other overpressure protection device	Current design standards
52	Gate / Feeder Station pressure regulator malfunction open leading to overpressure	Murray Costello	Failure of regulating pressure at Gate, Feeder and District stations, leading to exceeding pressure at downstream network, potential of loss of containment at the weakest link (e.g. valves, pipes, fittings, and customer appliances), subsequently result to significant interruption of supply, H&S impact to public and worker and increase in green house gas emission	Equipment malfunction	Regulator failure	Exceeding pressure of downstream network, potential of loss of containment at the weakest link (could be at valves, pipes, fittings, and customer appliances), potential release of natural gas above ground or inside buildings, leading to fire / explosion.	- Station Operational Inspections - Station Maintenance Inspections - Telemetry Maintenance Inspections - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan) - Overpressure protection
58	Obsolete regulator and pressure relief	Murray Costello	Obsolete regulator and relief equipment. Age and design may impair functionality resulting in overpressure. Lack of replacement parts may be an issue for some equipment.	Equipment malfunction	Obsolete regulator and relief equipment.	Age and design may impair functionality resulting in overpressure. Lack of replacement parts may be an issue for some equipment.	Regular testing and inspections. Capital replacements as required
60	Odourant under odourization	Murray Costello	Loss of odourant due to masking of odourant or odour fade in gas piping systems due to absorption, adsorption or oxidation of odourant or odourizer malfunction. These could lead significant loss of odorant in distribution system, subsequently inability to detect leaks by the general public and increase greenhouse gas emissions. If large scale failures are developed, could have H&S impact to public and GDS worker	Operate beyond allowable limits	1. Physical and / or chemical processes including adsorption, oxidation. Note: Occurs predominantly in installations of new pipe rather than in existing pipe. It is more pronounced in new steel pipe of larger diameters and longer lengths. However, it can also occur in plastic pipe and in smaller and/or shorter pipe installations. New pipeline installations or additions of new piping segments may require the conditioning of the pipe before it is placed into service to prevent occurrences of odour fade. If a natural gas leak occurs underground, the surrounding soil may cause odour fade. Other factors that may cause odor fade include: conditions related to the construction and configuration of the customer's gas facilities; the presence of rust, moisture, liquids or other substances in the pipe; and gas composition, pressure and/or flow. Intermittent, little or no gas flow over an extended period of time may also result in the loss of odorant until gas flow increases or becomes more frequent. 2.Odorization equipment failure (injection and metering equipment) 3.Human factors leading to inadequate odorization in natural gas.	Inability to detect leaks by the general public. This could delay leaks reporting, subsequently increase green house gas emission. If large scale failures are developed, could have H&S impact to public and GDS worker. Z662 Code compliance issue	-C&M Manual- Pre-odourization of Steel Pipe - Odorant Sniff Checks - Odorant Monitoring - odorant Analysis - odorant Survey - Leak Monitoring - Leak Survey - SCADA alarms, remote diagnostic (at all SCADA sites) -CSA Z662 compliance requirement (Section 4.21) - states the minimum safety requirements for gas odourization.
63	Odourant over odorization	Murray Costello	Over odourization of gas in distribution system or release of odourized gas into atmosphere.	Incorrect operation	1. Odorization equipment failure (injection and metering equipment) 2. Human factors leading to over odorization in natural gas.	Misinterpretation of natural gas leaks or over reporting of mistaken odourization for natural gas leaks	-Sniff Test -SCADA alarms, remote diagnostic -Operating Procedures (GDL Operations Services Section 10) and associated training
67	Metering gas quality out of specification	Clancy O'Hara	Off spec gas (e.g. high moisture)	Off spec gas	Equipment failure or human error	Impact reliability of supply gas to customers	Monitoring/SCADA
68	Lack of Training and Competency for Viessman Equipment	Murray Costello	Viessmann boilers do present some unique maintenance and operational challenges relative to other types, as they use more proprietary controls systems not as easily understood as other boilers	Incorrect operation	Challenges in maintaining and operating Viessmann boilers due to the use of proprietary controls systems	Potential inappropriate maintenance and operation of boilers, impacting operational performance	Call 3rd party (qualified contractor) for service and adjustments Training for technicians on various types of equipment Integrated procedures for all heating equipment (including hydronic boilers which include Viessman)
69	Inoperable by-pass valves at stations in the DO system	Murray Costello	Inoperable by-pass valves at station could lead to inability to bypass station in case of emergency	Degradation	Equipment failure	In an emergency scenario we would not be able to bypass the station and we would have to shut in the station completely and possibly lose the downstream customers. There is also a smaller risk that we could open the valve to open the bypass and not be able to close it; however, this is very unlikely.	New station designs incorporate extra valves in bypass where practicable Ongoing valve maintenance, C&M Manual
70	Below Grade Vaulted Stations	Murray Costello	Below grade vaulted stations are no longer a standard design for system stations at Union Gas. Existing facilities present a number of risks: 1. Downstream over pressure due to lack of drain in relief valve stacks. 2. Structural deterioration and collapse which could lead to over or under pressure. 3. High pressure cuts are subject to frost heave on outlet pipe and wafer style regulators have reduced resistance to stresses	Equipment malfunction	Below grade vaulted stations are no longer a standard design for system stations at Union Gas.	Existing facilities present a number of risks: 1. Downstream over pressure due to lack of drain in relief valve stacks. 2. Structural deterioration and collapse which could lead to over or under pressure. 3. High pressure cuts are subject to frost heave on outlet pipe and wafer style regulators have reduced resistance to stresses	Periodic inspections Capital replacements as required
71	Obsolete Station Heating Equipment in DO system	Murray Costello	Obsolete station heating equipment presents challenges to find parts for repair, leading to significant cost increase and increased effort to maintain operation during peak heating season	Degradation	Parts not available for obsolete station heating equipment	When failure happens reinstating the existing heating system can be difficult as parts may no longer be available which could drive significant costs and mitigation efforts to keep the station operating during the peak heating season.	Regular testing and inspections A prioritized list of all heating equipment has been created to aid in planned capital replacements
72	Indirect Fired Heaters at stations in SW and SE Districts (Glycol Leaks at Stations)	Amanda Murray	Glycol leaks found with indirect fired heaters at stations in SW and SE districts	Degradation	There have already been several environmental spills (glycol) as a result of condition failures at these heaters. Also, the condition of the heaters is creating risks around reliability and the ability to adequately provide heat.	Some of these heaters are in close proximity to water wells and watercourses. Some of these heaters on stations that feed a large number of customers.	Replacement program in asset plan Emergency Response Procedure for leak clean-up BMS (Burner management systems) controls w/ alarms and operator action
76	Incorrect setting for Measurement Device in DO system	Murray Costello	Meter setting at large customer stations could be incorrect leading to complaints from large customers	Incorrect operation	Inaccurate setting of meter at large customer stations due to human factors	Inaccurate metering of gas for large customers	The first phase of the meter accuracy project to validate technician setting in the field at large customer stations has been completed.
78	Pressure testing stations in DO deviate from design specs	Murray Costello	If pressure testing of stations deviate from design specs, there is potential for stations to fail within intended operating pressure limits	Incorrect operation	Workers are not aware of revised pressure testing spec	Incorrect pressure testing of stations impacting customers	C&M Procedures
79	Pressure testing station fittings/piping > 700 kPa deviate from specification	Jennifer Burnham	If pressure testing of stations deviate from design specs, there is potential for stations to fail within intended operating pressure limits	Incorrect operation	Workers are not aware of pressure testing spec	Incorrect pressure testing of stations impacting customers	C&M Manual CSA Z662
80	Customer load changes downstream of sales stations	Brad Clark	Unauthorized load additions to the network could increase load of network	Incorrect operation	Unauthorized load additions	Increase load of the network, potential impact operational reliability	CARS requests, Station 180s
81	Incorrect operation of DO stations	Murray Costello	Operators may not be up to date with technological changes to DO stations, hence stations may not be operated correctly leading to operational issues	Incorrect operation	Operators are not up to date with technological updates of stations	Impact station operation	Shoulder-to-shoulder training, some external courses
82	Operational philosophy of stations	Wes Armstrong	As not all stations have documented operational philosophy, STO stations may not be operated correctly leading to operational issues	Incorrect operation	Lack of process to ensure the documentation is completed prior to handover to operations.	Operational interruption which could result in H&S impact	Some stations have documents, personnel develop documents and or experienced based understanding
83	Engineering design errors on station design/redesign	Tracey Teed Martin	Engineering design errors on station leading potential operational issues	Design error	Engineering design errors on station	Leading to potential operational issues	Stations double-checked by Senior Engineers
85	Electrical faults during energization of high voltage facilities	Jennifer Burnham	High voltage (greater than 750 volts) energization of plant pipe from hydro facilities, falling lines (cogens and major industrial customers, hydro corridors). i.e. electrical fault.	Contact with electrical voltage and exposure to electrical arc flash	Malfunction of electrical equipment	Potential worker H&S impact	- Some grounding, some DC Decouplers, Grounding Loop, gravel. - There is a screening study maintained by the electrical and controls group to determine when an AC mitigation study is required. - Distance from source of electricity
86	Electrical inspectors for station construction	Neil MacNeil	Lack of EGI hired electrical inspectors for construction projects. EGI electrical inspectors are rarely hired to verify installation per design drawings.	Inspection deficiency	Inadequate inspection resources on projects resulting in non-compliances and deficiencies	potential non-compliance and/or unsafe situation.	Electrical Inspectors, communications of requirements. ESA inspectors are required for all electrical installations to verify installations are done per Ontario Electrical and Safety code requirements only and do not verify installations completed per design drawings.
87	Station electrical grounding	Murray Costello	Ground network integrity for equipment protection	Contact with electrical voltage and exposure to electrical arc flash	Inadequate grounding of electrical equipment at station	Potential worker H&S impact	Grounding standard testing procedures and training.
88	Station hazardous area classification	Rob Sterling	Equipment not correctly rated for the hazardous area.	Design error	Incorrect rating for hazardous area	Not comply with regulatory requirement	ST-20-03E6-B9AA - Hazardous Area Classification Standard' covers the hazardous area classification for Enbridge Gas facilities.
89	Station electrical system maintenance	Murray Costello	There is a potential risk due to insufficient maintenance of electrical equipment (e.g. panels, cables, etc.). Right now there is a lack of maintenance plans and consistent procedures for electrical equipment.	Electrical/controls malfunction	Malfunction of electrical equipment	Possible worker injury if exposed to electrical energy from malfunctioned equipment	Most of the downgraded electrical assets were upgraded or rectified over the last 7 -8 years through LUG electrical capital upgrade program
91	Station rodent issues	Wes Armstrong	Station rodent issues which could lead to potential fire	Natural forces/weather	Rodent issue at stations	Potential for fires in equipment due to animals damaging equipment by building nests and damaging our wiring.	Installed some traps and placed poison Routine Inspection

Current ID	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
36	Detect Prevent	Operational reliability	Financial	6	2						Risk Owner updated from A.S on August 1, 2023		MP-01: Asset	2021-06-28
39	Detect, Mitigate	Operational reliability	Operational	3	5			In year 2 of 3 of replacing valves. Targeting 80 or 90 to be completed in 2017.	Kirby Skinn-Jones	Q3 2021	Treatment Owner changed to Kirby Skinn-Jones 2/8/2023 Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2023-02-08
40	Detect Detect Mitigate	Operational reliability	Financial	1	3						Additional controls added from LGD risk ID 38. Risk Owner updated from A.S on August 1, 2023		MP-01: Asset	2021-08-25
41	Prevent Detect Detect Mitigate	Operational reliability	Operational	1	6						Additional controls added from LGD risk ID 18. Risk Owner updated from A.S on August 1, 2023		MP-05: Integrity	2021-08-25
42	Prevent Prevent	Public safety	Health & Safety	2	5							Financial L6C2 Medium	MP-01: Asset	7/4/2022
47	Detect Prevent	Public safety	Reputational	3	3						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022		MP-01: Asset	6/20/2022
48	Prevent	Operational reliability	Operational	3	5							Financial L1 C2 Low Risk	MP-01: Asset	06/14/2021
49	Detect Prevent	Public safety	Health & Safety	2	6							One RR only	MP-05: Integrity	7/4/2022
50	Detect Prevent Prevent Mitigate	Public safety	Reputational	5	2								MP-05: Integrity	6/21/2021
51	Prevent	Public safety	Health & Safety	1	6							One RR only	MP-01: Asset	7/4/2022
52	Prevent Prevent Prevent Mitigate Prevent	Public safety	Health & Safety	2	5							Financial, Operational, Reputational - Medium	MP-01: Asset	2021-06-24
58	Prevent, Detect Prevent	Public safety	Health & Safety	3	5							One RR only	MP-01: Asset	6/23/2021
60	Prevent Detect Detect Detect Detect Detect Detect Detect Detect Prevent	Public safety	Operational	7	2						23/03/2023 AMH - Revised Controls per Discussions with Dale Smith	Environmental: L7 C2 Medium Reputational: L7 C1 Medium H&S: L7 C1 Medium	MP-01: Asset	2021-06-23
63	Detect Detect Prevent	Operational reliability	Reputational	4	4						23/03/2023 AMH - Updated controls per Dale Smith	Environmental: L3 C1 Low Financial: L3 C1 Low H&S: L3 C1 Low Operational: L3 C4 Med	MP-03: Environmental	2021-06-23
67	Detect	Operational reliability	Reputational	5	3						Treatment completed Q2 2023	One RR only	MP-01: Asset	2021-06-28
68	Prevent Prevent Prevent/Mitigate	Operational reliability	Operational	6	3			Operations and technical training-training on new procedures Q1 2022	Bridget Sneddon	2022	Treatment completed Q2 2023	One RR only	MP-01: Asset	2023-05-02
69	Prevent	Operational reliability	Operational	5	4							One RR only	MP-01: Asset	2021-06-11
70	Prevent, Detect Prevent	Operational regulation	Operational	3	5			Prioritized replacements of older stations in areas prone to frost heave such as water table and soil structure.	Michael Vettesse	2024	Corrected treatment owner name spelling	One RR only	MP-01: Asset	2022-07-19
71	Detect Prevent	Operational reliability	Operational	3	5							One RR only	MP-01: Asset	2021-06-25
72	Prevent Mitigate Detect	Operational reliability	Environmental	4	3			All indirect fired heaters in the Legacy Union Gas franchise have been site visited and risk assessed. A multi-year replacement plan has been developed. Current short-term mitigation plan is monitoring of fluid levels of Indirect Fired Heaters.	Michael Vettesse	2034	Corrected treatment owner name spelling treatment plan update 10/13/2022 High risks are mitigated Q4 2022, Risk Ranking updated - 1/31/2023	One RR only	MP-01: Asset	2023-01-31
76	Prevent	Operational reliability	Reputational	5	3							One RR only	MP-01: Asset	2021-06-11
78	Prevent	Public safety	Reputational	5	3							One RR only	MP-01: Asset	2021-06-15
79	Prevent Prevent, Detect	Public safety	Reputational	7	2							One RR only	MP-01: Asset	2021-06-23
80	Prevent	Operational reliability	Operational	4	2							One RR only	MP-01: Asset	2021-06-23
81	Prevent	Operational reliability	Operational	3	4							One RR only	MP-01: Asset	2021-06-18
82	Prevent	Operational reliability	Operational	2	6							One RR only	MP-01: Asset	2021-06-28
83	Prevent	Operational reliability	Operational	3	4						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
85	Prevent Detect Prevent	Workforce safety	Health & Safety	1	5							One RR only	MP-04: Health & Safety	2021-06-23
86	prevent	Operational regulation	Reputational	3	3							One RR only	MP-01: Asset	7/4/2022
87	Prevent	Workforce safety	Health & Safety	1	4							One RR only	MP-05: Integrity	2021-06-11
88	Prevent	Operational regulation	Health & Safety	2	4						03/27/2023 AMH - Updated controls and Risk Owner from A. Nossair to R. Sterling	One RR only	MP-01: Asset	2021-06-11
89	Detect & Prevent	Workforce safety	Health & Safety	3	5							One RR only	MP-05: Integrity	2021-06-11
91	Prevent, Mitigate Detect	Public safety	Health & Safety	3	3							One RR only	MP-05: Integrity	2021-06-23

First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version	Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard	Source	Consequences	Controls	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									59	LUG	FINAL	92	Station frost heaving	Murray Costello	Frost heave creating maintenance issues as well as potential mechanical failures due to excessive stress with potential for adjacent property damage	Natural forces/weather	Frost heave at stations	Creating maintenance issues as well as potential mechanical failures due to excessive stress with potential for adjacent property damage	- Station engineering calculates heat requirements and designs accordingly, budget submissions for upgrades - Design to allow for non-damaging frost heave	Prevent Prevent	Operational reliability	Operational	3	4							One RR only	MP-01: Asset	44358
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate										60 - System Stations / All System Stations	LUG	FINAL	93	Station flooding	Tara Kuuskman	Flooding causing under/over pressure	Natural forces/weather	Flooding impacting station	Lead to potential under / over pressure at station	- Design-redundancy, OPPD, SOP - Remote monitoring - ERP, plans developed for high risk areas - Notifications of high water levels by conservation authority	Prevent Detect Mitigate Detect	Operational reliability	Operational	5	3						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2021-05-30
2. Pipeline transportation of natural gas	2.6. Aggregate	2.4.5. Transportation Aggregate	2. Ontario Transportation	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									67	LUG	FINAL	95	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Prevent Prevent Prevent	Terrorism & asset security	Operational	2	5							One RR only	MP-06: Security	2021-06-28
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											68	LUG	FINAL	98	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Prevent Detect Mitigate Detect, Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Operational	3	5							One RR only	MP-06: Security	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											69	LUG	FINAL	99	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Prevent, Detect Mitigate Prevent Detect Mitigate Detect, Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Operational	3	2							One RR only	MP-06: Security	2021-06-11
2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											26	LGD	FINAL	100	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Prevent, Detect Prevent, Detect Prevent Mitigate	Terrorism & asset security	Health & Safety	1	5							Financial : L2C3 Reputational : L2C3	MP-06: Security	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											71	LUG	FINAL	102	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Prevent, Mitigate	Terrorism & asset security	Health & Safety	1	6							One RR only	MP-06: Security	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											72	LUG	FINAL	103	Construction damage to existing facility	Wes Armstrong	Construction within an operating facility (Brownfield), equipment damage, property damage, first aid injuries, system outages	2nd party damage	Damage of site asset due to 2nd party construction activities	Potential impact to operations	HWP, tie in procedures, inspection, defined outage windows, experienced contractors	Prevent, Mitigate	Operational reliability	Operational	5	4							One RR only	MP-01: Asset	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											73	LUG	FINAL	104	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Prevent Detect	Operational reliability	Operational	3	4							One RR only	MP-01: Asset	2021-06-14
dour	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											74	LUG	FINAL	105	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Prevent Prevent, Mitigate	Operational reliability	Operational	2	5							One RR only	MP-01: Asset	2021-06-29
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											75	LUG	FINAL	106	Storage Tank Corrosion STO	Tara Kuuskman	External/internal corrosion (for storage tank only) that may lead to a leak.	Corrosion external	External / internal corrosion over time may progress through 100% of storage tank wall if not remediated **Note on Hazards** Other hazard is Corrosion internal	Leak to atmosphere leading to operation interruption as extended time could be required to repair	- Spot inspections - corrosion control program (leak survey, coating) - ERP -Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, and ERP (Emergency Response Plan)	Prevent, Detect Prevent, Detect Mitigate	Operational reliability	Operational	3	5						Additional controls added from LGD risk ID 38. Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2021-08-25
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											78	LUG	FINAL	109	STO Corrosion of Instrument Air Compressors	Jeff Falkiner	Air compressor systems - internal corrosion due to moisture in air	Corrosion internal	Internal corrosion over time due to air moisture	Impair performance of air compressor systems	Air dryers, filters, chillers, dry gas seals, system backup through other air compressors	Prevent	Operational reliability	Operational	5	4							One RR only	MP-05: Integrity	7/4/2022
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											79	LUG	FINAL	110	STO Boilers	Tara Kuuskman	Boilers - insulated buried coolant lines (would lose C plant)	Corrosion external	Corrosion of coolant lines	Impair performance of boilers	Alarming	Detect	Operational reliability	Operational	5	4						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2021-05-30
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											80	LUG	FINAL	111	STO Corrosion on Pipe Supports	Wes Armstrong	Corrosion on pipe supports	corrosion external	External corrosion of pipe supports	Resources would be required to rectify the issue	Inspections and Maintenance Programs	Detect	Operational reliability	Operational	5	3							One RR only	MP-05: Integrity	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											81	LUG	FINAL	112	STO Corrosion Under Insulation on Suction or Discharge Compressor Piping	Tara Kuuskman	Corrosion under insulation on suction/discharge leading to leak	corrosion external	Under insulation corrosion at suction or discharge piping	Potential leak of natural gas	Gas detector	Detect	Operational reliability	Operational	3	5						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2021-05-30
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											82	LUG	FINAL	113	STO Gas Ingress into Buildings during ESD	Wes Armstrong	Location of unit and plant silencer stacks has potential of drawing gas into enclosure and gas generator under certain wind conditions during ESD. Identified at Bright A1&A2	Accidental release/LOC flammable gas	Location of unit and plant silencer stacks has potential of drawing gas into enclosure and gas generator under certain wind conditions during ESD.	Potential adverse event impacting operation	Gas Detection	Detect	Operational reliability	Operational	5	4						Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023	One RR only	MP-01: Asset	2023-02-28
2. Pipeline transportation of natural gas	2.1. Station	2.2.1. Compression Facility	2. Ontario Transportation											83	LUG	FINAL	114	STO Compressor System Design Errors	Wes Armstrong	Design errors during Compressor Stations Partnerships Design and construction specs, standards and philosophy differences causing rebuild and re design, increased general maintenance	Design error	Design errors during Compressor Stations Partnerships Design and construction specs, standards and philosophy differences causing rebuild and re-design	Increased general maintenance and impact customers	Oversight, testing and code requirements/standards	Prevent	Operational	Operational	5	4							One RR only	MP-01: Asset	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											84	LUG	FINAL	115	Improper Station Construction	Wes Armstrong	Improper station construction - not following drawings (changing station capacity, etc.)	Construction defect	Improper station construction - not following drawings (changing station capacity, etc.)	Impact operation	Site inspections C&M documents to ask engineering for changes, as-building OMS structure, Consistency amongst consultants	Detect Prevent Prevent	Operational reliability	Operational	3	3							One RR only	MP-01: Asset	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											86	LUG	FINAL	117	Non-vehicle floor grating, capacity rating	Wes Armstrong	Non-vehicle floor grating, capacity rating	Falls from elevation	Vehicle does not meet capacity rating of floor grating	Vehicle damage	Signage is posted indicating "No equipment permitted on floor grating without prior verification of weight limitation"	Prevent	Workforce safety	Health & Safety	3	5						Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023	One RR only	MP-04: Health & Safety	2023-02-28
2. Pipeline transportation of natural gas	2.1. Station	2.2.1. Compression Facility	2. Ontario Transportation											87	LUG	FINAL	118	Deterioration of structural integrity (frame, roof)	Wes Armstrong	Deterioration of structural integrity (frame, roof)	Degradation	Deterioration of compressor building structure (Frame, roof)	Impact operation	Developed a building inspection program	Prevent, Detect	Operational reliability	Operational	3	4						Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023	One RR only	MP-01: Asset	2023-02-28
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											88	LUG	FINAL	119	Reliability of Remote Storage Reciprocating Units (Waubuno)	Wes Armstrong	Concerns with reliability of remote reciprocating units - no spare parts available for old recip mechanical parts. Potentially impacting deliverability	Degradation	Older reciprocating compressors are a concern for failure of components and for some units, there are no spare parts available.	Lack of operability of these remote reciprocating units could impact storage deliverability, leading to financial consequences	Maintenance Program and STO condition monitoring program. Emergency Response Program	Prevent, Detect Mitigate	Operational reliability	Financial	5	5			**Short Term Risk Treatment** Purchase gas on the spot market and review annual maintenance checks for leading indicators of compressor failure **Long Term Risk Treatment** Preferred solution alternative to be determined based on outcome of RAM study	Paul Norris	2026	Treatment plan due date changed from 2024 - 2025 07/19/2022 treatment plan update 10/13/2022 Treatment owner updated 1/31/2023 Q4 2022 Update: -Dawn to Corunna pipeline project was approved by the OEB in November 2022 -TotEx Value Modelling has begun for Waubuno Q1 2023 Update: Waubuno RAM Study in Progress	One RR only	MP-01: Asset	2023-01-31
2. Pipeline transportation of natural gas	2.1. Station	2.2.1. Compression Facility	2. Ontario Transportation											90	LUG	FINAL	121	Siemens will no longer support 24 C	Wes Armstrong	Reliability concerns as a result of failure of a 24C unit. There are currently 5 of the 24C units on the system. Siemens will no longer support 24 C (particular compressor model).	Degradation	Reliability concerns as a result of failure of a 24C unit. There are currently 5 of the 24C units on the system. Siemens will no longer support 24 C.	Impact operation	Maintenance Program and STO condition monitoring program. There are currently (Jan, 2015) spare parts available, but there may not be in the near future	Prevent, Detect	Operational reliability	Operational	3	4							One RR only	MP-01: Asset	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											91	LUG	FINAL	122	STO Leaking Valves	Wes Armstrong	Gas loss at STO sites due to leaking valves.	Equipment malfunction	Leaks from valves	Impact to operation	Valve inspections, Valve replacements	Detect, Prevent	Operational reliability	Operational	6	3							One RR only	MP-05: Integrity	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											92	LUG	FINAL	123	Dawn Auxiliary Boiler 2	Wes Armstrong	Boiler failure (needed to heat fuel gas, beyond LCU) at Dawn Aux 2.	Equipment malfunction	Boiler failure (needed to heat fuel gas, beyond LCU) at Dawn Aux 2.	Financial impact due to equipment out of service	Alarms, annual maintenance, spare parts	Detect & Prevent	Operational reliability	Financial	1	5							One RR only	MP-05: Integrity	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											94	LUG	FINAL	126	Switch gear (Aux 2 and 4)	Wes Armstrong	Switch gear (Aux 2 and 4) - hazard risk category HRC 4 (extreme danger to employee) called out as part of Arc Flash study at STO	Contact with electrical voltage and exposure to electrical arc flash	Switch gear (Aux 2 and 4)	Workers could be exposed to Arc Flash	Arc flash risk assessment labeling in place have purchased HRC 4 approach suits and have procedures in place management involved in any energized or HRC 3+ tasks	Detect Prevent Prevent Prevent	Workforce safety	Health & Safety	1	6							One RR only	MP-04: Health & Safety	2021-06-14
2. Pipeline transportation of natural gas	2.1. Station	2.2.1. Compression Facility	2. Ontario Transportation											95	LUG	FINAL	127	Compressor unit outage	Wes Armstrong	All but Parkway. Loss of unit (outage impacting system capacity) - mechanical, UPS or local control system failure	Equipment malfunction	Mechanical, UPS or local control system failure	All but Parkway. Loss of unit (outage impacting system capacity) impact operation	LCU redundancy, remote monitoring, call out	Prevent & Detect	Operational reliability	Operational	1	6							One RR only	MP-08: Control Room	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											99	LUG	FINAL	131	Gas quality off spec.	Clancy O'Hara	Metering gas quality out of specification	Off spec gas	Off spec gas	Impact customers	Procedures to adjust, monitoring/SCADA	Mitigate & Detect	Operational reliability	Operational	5	3							One RR only	MP-08: Control Room	2021-05-30
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											100	LUG	FINAL	132	STO Incorrect volumetric metering	Clancy O'Hara	Metering incorrect volumetric measurement	Equipment malfunction	Metering equipment malfunction	Impact customers	- Alarms, meter verification, self diagnostics - redundancies (major cuts.) SOP, check measurement at STO	Detect Prevent	Operational reliability	Operational	5	3							One RR only	MP-01: Asset	2021-05-30
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											101	LUG	FINAL	133	STO loss of gas flow	Wes Armstrong	Closing valves, under/over pressure, freeze-off	Equipment malfunction	Equipment malfunction or human error leading to loss of gas flow	Potential impact to operations	- Design-redundancy, OPPD, SOP - remote monitoring, callout	Prevent Detect	Operational reliability	Operational	1	6							One RR only	MP-05: Integrity	2021-05-30
2. Pipeline transportation of natural gas	2.1. Station	2.2.1. Compression Facility	2. Ontario Transportation											102	LUG	FINAL	134	Gas generator failure	Clancy O'Hara	Unplanned failure multiple compressor unit - gas generator	Equipment malfunction	Failure of compressor unit - gas generator	Impact to operation	- Vibration monitoring, temperature monitoring, oil pressure monitoring - PM - attended/staffed, contingency plans for multiple unit failures	Detect Prevent Mitigate	Operational reliability	Operational	1	6							One RR only	MP-05: Integrity	2021-05-30
2. Pipeline transportation of natural gas	2.1. Station	2.2.1. Compression Facility	2. Ontario Transportation											103	LUG	FINAL	136	Reciprocating compressor failure	Wes Armstrong	Unplanned failure on reciprocating compressor plants	Equipment malfunction	Failure on reciprocating compressor plants	Impact to operation	- PM increased shutdowns - Protection devices - Remote monitoring and control - Daily inspections when in operations - If we were in a loss of throughput would rent additional unit.	Prevent Mitigate Detect Detect	Operational reliability	Operational	5	4							One RR only	MP-05: Integrity	2021-06-14
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											104	LUG	FINAL	137	Drip tank overfill	Wes Armstrong	Drip tanks - liquid carryover from tank to atmosphere	Environmental spill/HAZMAT release/loss of containment	Operator blowing drips when not aware of the tank level.	Environmental reportable spill	Level switches, alarms, dump valves	Prevent	Environmental	Operational	5	4			Testing of choker valves. In discussions with Jim Harradine and Darryl Stokes there are a number of investments being created to install level indication and alarming on drip tanks to ensure that the operator is aware of the level and potential risk of a spill. Edys Mills station has been completed. Copperleaf investment #100934, #102633: instrumentation program	Darryl Stokes	2025		One RR only	MP-03: Environmental	M. Hildebrand updated following conversation with Jim Harradine and Darryl Stokes May 31, 2021.
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											105	LUG	FINAL	138	STO Boiler outage	Wes Armstrong	Boilers outage due to lack of employees to service - competency training certification for working on boilers for our employees - require G1	Equipment malfunction	Boiler outage due to lack of employee to service	Financial impact due to equipment out of service	One employee with G1, outside contractors	Prevent	Operational reliability	Financial	1	5							One RR only	MP-05: Integrity	2021-06-01
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											106	LUG	FINAL	139	STO ESDV or vent valve fails open	Wes Armstrong	Any unit ESD valve/vent valve failure leading to uncontrolled gas atmosphere	Equipment malfunction	ESD valve / vent value prematurely lift	Financial impact due to operational impact / repair	Limit switch, yard valves, valve maintenance	Prevent, Detect	Operational reliability	Financial	3	3							One RR only	MP-05: Integrity	2021-06-01
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											107	LUG	FINAL	140	Yard valve drive key failure	Wes Armstrong	Shaft drive key failure on yard valve leading to valve and operator in two different positions (misleading indication)	Equipment malfunction	Shaft drive key failure on yard valve leading to valve and operator in two different positions (misleading indication)	Financial impact due to repair	Valve maintenance & inspection	Prevent, Detect	Operational reliability	Financial	3	3							One RR only	MP-05: Integrity	2021-06-01
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											109	LUG	FINAL	142	Gasket/flange leaks	Wes Armstrong	Gasket failure on flanges	Accidental release/LOC flammable gas	Gasket failure on flanges	Financial impact due to repair	Monitor system for leaks	Detect	Operational reliability	Financial	5	3							One RR only	MP-05: Integrity	2021-06-14
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											110	LUG	FINAL	143	Connection leaks	Wes Armstrong	Leaks at any connection points	Accidental release/LOC flammable gas	Leaks at any connection points	Financial impact due to repair	Leak detection	Detect	Operational reliability	Financial	3	3							One RR only	MP-05: Integrity	2021-06-01
2. Pipeline transportation of natural gas	2.1. Station	2.2.1. Compression Facility	2. Ontario Transportation											112	LUG	FINAL	145	Impellor/rotor failure	Wes Armstrong	Impeller/rotor failure	Equipment malfunction	Failure of impeller/rotor	Would result in the long-term outage of the compressor and operational impacts. The mitigating controls generally would be presence of LCU compressor	- Vibration monitor - Annual inspections - Scheduled Maintenance - LCU Compressor	Prevent Detect Prevent Mitigate	Operational reliability	Operational	3	4							One RR only	MP-05: Integrity	2021-06-14
2. Pipeline transportation of natural gas	2.1. Station	2.2.1. Compression Facility	2. Ontario Transportation											113	LUG	FINAL	146	Over greasing valves	Wes Armstrong	Maintenance of unit suction & discharge valves (Grove) - over greasing causes seizing of position Parkway B, Bright A1, A2, B	Incorrect operation	Inadvertent over greasing of compressor unit suction and discharge valves causing valve to become stuck in last position	Delayed operation while valves are being remediated	Routine preventative maintenance procedure	Prevent	Operational reliability	Operational	6	3						Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023	One RR only	MP-05: Integrity	2023-02-28
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											114	LUG	FINAL	147	STO Vibration	Wes Armstrong	Piping vibration	Vibration	Vibrations due to rotating equipment or gas flow through piping systems	Potential undetected / unmitigated excessive vibrations may lead to early equipment failure resulting in early replacement of equipment. Financial impact	Piping Engineering Design Operator rounds	Prevent, Detect	Operational reliability	Financial	3	3							One RR only	MP-05: Integrity	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											115	LUG	FINAL	148	Manual start up of equipment	Wes Armstrong	Manual starter - no PLC or remote control - injury during start-up	Incorrect operation	Inadvertent error during manual start of equipment	Possible worker injury	SOPs	Prevent	Workforce safety	Health & Safety	1	5							One RR only	MP-01: Asset	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											116	LUG	FINAL	149	Heat Exchanger Integrity	Tara Kuuskman	Integrity issue with heat exchangers - gas getting into glycol systems and venting inside building	Accidental release/LOC flammable gas	Integrity issue with heat exchangers - gas getting into glycol systems and venting inside building	Potential compliance issue	Operator Checks PM program inspections	Detect Detect	Operational regulation	Reputational	5	3						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2021-06-25
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											117	LUG	FINAL	150	Oil mist, potential for fire	Wes Armstrong	Oil mist (flash temperature - 500-700F?) leading to fire	Accidental release/LOC flammable gas	Oil mist (flash temperature - 500-700F?) leading to fire	Possible worker injury	Flame detection, oil pressure, oil tank levels	Detect & Prevent	Workforce safety	Health & Safety	5	4							One RR only	MP-01: Asset	2021-06-11
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											118	LUG	FINAL	151	Catastrophic failure of a gas-powered starter motor on a Siemens gas turbine	Wes Armstrong	Catastrophic failure of gas-powered (pneumatic) starter motor on start up –leading to collateral damage of fuel gas supply piping	Equipment malfunction	Catastrophic failure of gas-powered (pneumatic) starter motor during Startup **Note on hazards** Other applicable hazard is Accidental release/LOC flammable gas	The machine could potentially blow apart and cause collateral damage to the fuel gas supply piping which supplies the fuel for the turbine and the gas to drive the starter, leading to equipment damage and potential H&S impact	Gas detection, procedures	Detect & Prevent	Operational reliability	Health & Safety	3	4							One RR only	MP-01: Asset	2021-06-29

First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version	Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard	Source	Consequences	Controls	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											119	LUG	FINAL	152	Hot spots on exhaust stack of the power turbine (Compressor facility)	Wes Armstrong	Potential degradation of insulation at the exhaust stack on the power turbine, leading to hot-spots	Degradation	Degradation of insulation at the exhaust stack on the power turbine, leading to hot-spots	Leading to repair	month and annual Inspection program	Prevent Detect	Operational reliability	Financial	1	4							One RR only	MP-01: Asset	2021-06-03
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											120	LUG	FINAL	153	Dry gas blowby due to compressor seal failure	Wes Armstrong	Dry gas seal failure leading to gas venting at ground level through demister drain	Equipment malfunction	Dry gas seal failure leading to gas venting at ground level through demister drain	If worker is in the vicinity of the release, could expose to gas	- Relief valves - Separate vent lines - Reliefs inspected through PM	Prevent Prevent Prevent	Operational reliability	Health & Safety	1	2							One RR only	MP-01: Asset	2021-06-11
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											121	LUG	FINAL	154	No demister on drip tanks at compression facilities	Wes Armstrong	No demisters leading to oil spill	Design error	Non-standard design or demister that has been removed for some reason	Environmental reportable spill	Design standard	Prevent	Environmental	Reputational	5	2							One RR only	MP-03: Environmental	2021-05-30
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											122	LUG	FINAL	155	Crane failure at compressor sites	Wes Armstrong	Crane failure - use during pressurized vs. non-pressurized condition (pendant, hook, chains - Dawn C,D & Parkway A, Bright B only)	Dropped or falling objects	Crane failure due to inadvertent overloading or failure of crane component	Dropped load possibly landing on piping or equipment resulting in financial cost to replace damaged equipment	SOP e.g. Critical Lift Procedure	Prevent	Operational reliability	Financial	1	4							One RR only	MP-04: Health & Safety	2021-06-29
[redacted]																																						
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											128	LUG	FINAL	161	Procedural errors	Tracey Teed Martin	Lack of clarity around application of procedures could lead to non-compliance	Incorrect operation	Lack of clarity around application of procedures could lead to non-compliance	Leading to potential non-compliance	- C&M, STO manuals - Work packages, work place inspections	Prevent Prevent, Detect	Operational regulation	Reputational	5	3			Through the STO Track of CMP work, integration of work procedures (where not asset specific) and the development of new operational/maintenance procedures as part of the ESI Program. Original risk identified [this is no longer current information - but retained for posterity] SPECS, manual consolidation should be reviewed, STO PEMR process,	Louie Jeromel	2023	Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											129	LUG	FINAL	162	Lack of knowledge in Pressure testing > 700 kPa fittings for STO stations	Wes Armstrong	Lack of knowledge of requirement for pressure testing of fittings >700 kPa	Incorrect operation	Lack of knowledge of requirement for pressure testing of fittings >700 kPa	Leading to potential delay of work	C & M Manual, CSA Z662	Prevent	Operational reliability	Reputational	7	2							One RR only	MP-01: Asset	2021-06-23
2. Pipeline transportation of natural gas	2.2. Plant	2.2.4. CNG Facility	2. Ontario Transportation											130	LUG	FINAL	163	Hamilton Street Railway CNG	Tracey Teed Martin	Hamilton Street Railway - CNG facility. As this is the first CNG facility, an operating issue related to this site could potentially have a negative impact on our ability to market future CNG opportunities.	Incorrect operation	Operating issue	Potential reputation impact to the company's ability to market future projects	Design in progress as per applicable codes and standards and Enbridge design practices (Capital Development manages this project and determines requirements)	Prevent	Operational reliability	Reputational	3	5						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											131	LUG	FINAL	164	Station overpressure rupture	Wes Armstrong	Station piping over pressuring causing rupture	Accidental release/LOC flammable gas	Station piping over pressuring causing rupture	Potential fire / explosion impacting workers and public	- ESD - pressure monitoring - manual intervention	Prevent Detect Detect, Mitigate	Public safety	Health & Safety	1	6							One RR only	MP-01: Asset	2021-05-30
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											132	LUG	FINAL	165	STO Station piping minor overpressure causing code compliance issue	Wes Armstrong	Minor overpressure of Station piping causing code compliance issue	Incorrect operation	Incorrect set points for pressure testing	Minor overpressure of station piping leading to code compliance issue	Pressure monitoring and manual intervention	Prevent	Operational reliability	Reputational	5	4							One RR only	MP-01: Asset	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											133	LUG	FINAL	166	Community concerns near legacy UG STO sites due to operation / project activities, potential impact to company's reputation	Wes Armstrong	Community concerns at STO sites potentially resulting in reputation damage. Operational issues - roads, lights, driving on property not ours, and water issues - have resulted in a negative relationship with landowners near some of Union Gas STO sites. This has put us at risk for a potentially negative news story. Issues currently exits at Lobo and Bright, but could become an issue with additional facilities in the future.	Incorrect operation	Inadequate communication with communities near STO stations regards operation / project activities leading to community concerns such as impact to roads, lights disturbance, driving on property not ours, and water issues	Negative relationship with landowners near some of Union Gas STO sites. This has put us at risk for a potentially negative news story. Issues currently exits at Lobo and Bright, but could become an issue with additional facilities in the future.	Lands, Major Projects and Aecon (Constructor) have been notified to ensure that a protocol is set in place and followed for communications and reporting of landowner issues. Station Managers have been notified if a complaint is received to record the complaint and direct to the appropriate area.	Prevent & Detect	Stakeholder trust	Reputational	5	3						Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023	One RR only	MP-01: Asset	2023-02-28
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											135	LUG	FINAL	168	Power outage	Wes Armstrong	Hydro concerns - power outage for extended period of time (blackout - ice storm) - Lobo Admin generator	Loss of upstream feed	Utility power supply is interrupted	Power outage resulting in the need to use backup power sources for an extended period of time, increases the likelihood of a failure that could result in interruption on our ability to supply gas.	Backup generators, UPS, ERP	Prevent Prevent Mitigate	Operational reliability	Reputational	5	3						Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023	One RR only	MP-01: Asset	2023-02-28
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											136	LUG	FINAL	169	Obsolete MCCs and lack of spare parts at Compressor Sites	Wes Armstrong	Obsolete MCCs at Compressor Sites. In 2001, the manufacturer informed us that they would be making this line of equipment obsolete in the next 1 ½ years in favor of a new style. Parts availability will be affected. Equipment has now been obsolete for in excess of 15 years.	Obsolete equipment	In 2001, the manufacturer informed UGL that they would be making this line of equipment obsolete in the next 1.5 years in favor of a new style. Parts availability will be affected. Equipment has now been obsolete for more than 15 years.	An MCC failure could result in a compressor plant outage for a couple of weeks to complete a temporary repair. Depending on the time of year and system demands, this has the potential for significant losses.	Condition Monitoring Program, Spare Parts Emergency Response Program	Prevent, Detect Mitigate	Operational reliability	Operational	5	5			-Replace MCCs to the new standards -Program to address obsolescence by 2027. -Site specific projects identified	Paul Norris	2027	treatment plan update 04/28/2023 Q1 2023 Update: -Experiencing material delays (50 weeks ARO) and resource constraints -Aligning program with Obsolete Fire/Gas detection panel replacement program no longer possible -Major Compressor sites remaining: Dawn G (2025), Dawn E (2026), Dawn D (deferred to 2025), Lobo (Complete), Bright (deferred to 2025) and Parkway to be completed in 2026 -Long-term plan to replace obsolete MCCs at the Dawn auxiliary buildings and remote pool sites is under development -As units are replaced, spare inventories are generated	One RR only	MP-01: Asset	2023-01-31
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											137	LUG	FINAL	170	Obsolete Fire/Gas detection panels	Wes Armstrong	Obsolete Fire/Gas detection Panels at Lobo. The fire/gas PLC currently installed is now obsolete, parts are limited. Upgrade to current technology which is now being installed in all new compressor builds or possibly newer technology that would allow mounting of detectors in more accessible locations.	Obsolete equipment	The fire/gas PLC currently installed is now obsolete, parts are limited. A failure of the Fire/Gas detection panel or its associated detection system will shut down the compressor and not allow it to operate.	An Fire/Gas detection panel failure could result in a compressor plant outage for a couple of weeks to complete a temporary repair. Depending on the time of year and system demands, this has the potential for significant losses.	Condition Monitoring Program, Spare Parts Emergency Response Program	Prevent, Detect Mitigate	Operational reliability	Operational	5	5			-Replace Fire/Gas detection panel to the new standards to avoid a situation of unit unavailability impacting deliverability. -Site specific projects identified by year taking resources and criticality into consideration.	Paul Norris	2026	treatment plan update 10/13/2022 Treatment Owner updated 1/31/2023 Q4 2022 Update -Dawn D and Parkway East are to be installed and commissioned in Q2/Q3 2023 -Dawn E equipment will be ordered in 2023 with install/commissioning in 2024 -Control panel components impacted by the global chip shortage. Manufacturer is considering redesigning components to make use of another chip. -Equipment for Dawn D has either arrived or is in transit -Impacts to Parkway East and Dawn E are not known at this time Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023 Q1 2023 Update: Dawn D equipment has arrived, installation planned for 2023. Parts from Dawn D will support continued operation of Dawn E/G panels Dawn E equipment will be ordered in 2023 with install/commissioning in 2024 Dawn G equipment will be ordered in 2024 with install/commissioning in 2025 Parkway East deferred from 2023 budget Control panel components impacted by the global chip shortage. Aligning program with Obsolete MCCs at Dawn D, E, G no longer possible Major Compressor sites at Dawn, Lobo, Bright and Parkway to be complete in 2026 Long-term plan to replace remaining obsolete F&G systems at remote pool sites is under development As units are replaced, spare inventories are generated	One RR only	MP-01: Asset	2023-02-28
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											138	LUG	FINAL	171	Obsolete Allen Bradley PLC control system at STO	Wes Armstrong	Obsolete Allen Bradley PLC control system. Legacy Union Gas has an aging fleet of Allen Bradley PLCS series programmable logic controllers. This platform is nearing its life expectancy and is no longer being supported by the vendor.	Obsolete equipment	Across the company on both storage and transmission sites, there is an aging fleet of Allen Bradley PLC5 series programmable logic controllers. This platform is nearing its life expectancy and is no longer being supported by the vendor.	An PLC failure could result in a compressor plant outage for a couple of weeks to complete a temporary repair. Depending on the time of year and system demands, this has the potential for significant losses.	Condition Monitoring Program, Spare Parts Emergency Response Program	Prevent, Detect Mitigate	Operational reliability	Operational	5	5			-Replace PLCs to the new standards -Program to address obsolescence by 2026. -Site specific projects identified	Paul Norris	2026	treatment plan update 04/28/2022 Q1 2023 Update: -Experiencing material delays (waiting for modules from 2022 orders) and resource constraints -Bright B equipment has been ordered. Expected delivery Nov 2023, installation shifted to 2024 -Long-term plan to replace remaining obsolete PLCs across enterprise is under development -As units are replaced, spare inventories are generated	One RR only	MP-01: Asset	2023-01-31
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation											139	LUG	FINAL	172	High Voltage Energization	Holly Adams	High Voltage Energization of plant pipe from hydro facilities, falling lines(cogens and major industrial customers, hydro corridors)	Accidental exposure to electrical voltage	Equipment malfunction or human error during high voltage energization of plant pipe from hydro facilities (e.g. Cogens and major industrial customers, hydro corridors)	Potential worker H&S impact	Some grounding, some solid state decouplers	Prevent, Mitigate	Workforce safety	Health & Safety	1	6							One RR only	MP-04: Health & Safety	2021-06-23
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											140	LUG	FINAL	173	Marmin clamp filters	Wes Armstrong	Marmin clamp filters - no pressure indication - hazard when servicing if still pressurized	Exposure to energized systems (compressed gas)	Inadvertently servicing filter when system still contains pressure	Possible worker injury due to unexpected exposure to pressurized gas system	Standard work procedures e.g. LOTO	Prevent	Workforce safety	Health & Safety	5	4							One RR only	MP-01: Asset	2021-06-14
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											141	LUG	FINAL	174	Control valves - potential gas source during ESD	Wes Armstrong	Control valves - potential gas source during ESD	Accidental release/LOC flammable gas	Planned or unplanned emergency shutdown causes gas powered control valves to vent gas in order to go to "fail safe" position	Venting gas may disperse into flammable mass with the potential to ignite if an ignition source is also present resulting in delayed operation to restart plant in order to wait until vented gas has dispersed below flammable limits	Hazardous Area Classifications minimizing ignition sources	Mitigate	Operational reliability	Operational	3	4							One RR only	MP-01: Asset	2021-06-28
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											142	LUG	FINAL	175	Inability to monitor sprinkler system at Dawn I, Parkway B	Wes Armstrong	Sprinkler system - availability of supply, no indication on isolation valve for pressure monitoring (Dawn I, Parkway B)	Design error	Loss of supply for sprinkler system	Inability to monitor sprinkler system supply due to no indication available in design	Current design standards	Prevent	Operational reliability	Operational	1	5							One RR only	MP-01: Asset	2021-06-11
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											143	LUG	FINAL	176	Ineffective Location of Gas Detection Sensors	Wes Armstrong	Gas detection system - location of detectors in engine enclosure leading to ineffective detection (Dawn - I Plant, Bright A1 & A2, Parkway A & B)	Design error	Inadequate location of gas detectors in compressor engine enclosure	Ineffective gas detection	Internal design review process	Prevent	Operational reliability	Operational	3	5						Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023	One RR only	MP-01: Asset	2023-02-28
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											144	LUG	FINAL	177	No gas detection on air intake Identified at Parkway A	Wes Armstrong	No gas detection on air intake Identified at Parkway A	Design error	Inadequate location of gas detectors on air intake for compressor engine	Ineffective gas detection	Internal design review process	Prevent	Operational reliability	Operational	6	3						Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023	One RR only	MP-01: Asset	2023-02-28
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											145	LUG	FINAL	178	Lack of formal lightning Protection Integrity program.	Wes Armstrong	Lack of formal lightning Protection Integrity program.	Degradation	Degradation of lightning protection	Inability to protect equipment from lightning damages	All current inspections are being completed. In the absence of a formal program, nothing more can practically be done.	Prevent	Operational reliability	Financial	1	3						Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023	One RR only	MP-01: Asset	2023-02-28
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											146	LUG	FINAL	179	Flooding causing under/over pressure at STO station	Wes Armstrong	Flooding at STO Station causing under/over pressure	Natural forces/weather	Flooding at STO Station causing under/over pressure	Leading to operational impact	- Design-redundancy - OPPD, SOP - remote monitoring, callout	Prevent Prevent Detect	Operational reliability	Operational	1	2							One RR only	MP-01: Asset	2021-06-11
3. Aggregate			3. Aggregate											38	LGD	FINAL	184	Landslide and Earthquake in distribution and transmission systems	Ryan Werenich	Landslide / earthquake took place leading to potential significant failure of assets	Natural forces/weather	Landslide and Earthquake	Potential significant failure of assets	- Reinforced grade (for landslide hazard) - Landslide monitoring during flooding/heavy rainfall in high risk areas (for landslide hazard) - Predetermined isolation plans to isolate gas supply when events occur - Depth of Cover Mitigation - Depth of Cover Survey - Pipeline Patrols - MP Manuals, EM (Emergency Management) exercises, Contingency plans, Business Continuity Management (BCM) Program	Prevent Detect Mitigate Prevent Detect Prevent / Detect Mitigate	Operational reliability	Operational	3	5			Treatment plan complete. New geohazard model has been integrated into the TIMP risk model which evaluates geotechnical (slope movement), hydrotechnical (waterbody), earthquake (lead clay) risks. These geohazard risks are monitored on a quarterly basis and results are measured against the SR and IR safety targets	1) Miaad Safari	1) End of 2021	1) Incorporate Geohazards (excluding earthquake for now) in TIMP model in order to better understanding risk elements at locations where these hazards are active Treatment plan completed. Will stay on RR. 5/2/2023 Risk Owner Updated from A.S. August 1, 2023	One RR only	MP-05: Integrity	2023-08-01
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation											149	LUG	FINAL	185	Tornado at STO	Wes Armstrong	Tornado	Natural forces/weather	Tornado event	Shutdown of facility in event of tornado resulting in disrupted operations	Air raid sirens ERP	Mitigate	Operational reliability	Operational	3	5							One RR only	MP-01: Asset	2021-06-11
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution											36	LGD	FINAL	186	Tornado at DSO	Steve McGivery	Tornado could damage above ground gas carrying assets such as Gate Stations, residential meter sets, or could damage below grade services or even mains	Natural forces/weather	Tornado event	Likely to damage above ground assets but it could impact below ground assets as well, leading to release of natural gas, potential loss of customers.	- Emergency preparedness and response procedure - Predetermined isolation plans to isolate gas supply when events occur - MP Manuals - EM (Emergency Management) exercises - Contingency plans - Business Continuity Management (BCM) Program	Mitigate Mitigate Detect Mitigate Mitigate Mitigate Mitigate	Operational reliability	Operational	5	4							One RR only	MP-02: Emergency	7/4/2022
2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											217	LUG	FINAL	188	3rd party damage to wellhead	Wes Armstrong	A local farmer or resident inadvertently –impacted the well with a piece of equipment leading to well damage	3rd party damage	Physical impact by equipment inadvertently	Damages of wells	Well head fences Emergency Response program Laneways at wells Individual wells can be isolated Station valves can be automatically closed. Emergency shutdown valves installed at some locations	Prevent Mitigate Prevent Mitigate Mitigate	Operational reliability	Financial	3	5							One RR only	MP-05: Integrity	2021-06-11
2. Pipeline transportation of natural gas	2.4. Storage	2.4.1. Pool	2. Ontario Transportation											221	LUG	FINAL	191	3rd party drilling into reservoir	Wes Armstrong	A third party has inadvertently drilled into the reservoir leading to reservoir damage	3rd party damage	3rd party inadvertently drilled into the reservoir	Damages of reservoir	- DSA (designated storage area), Well drilling permits only given by MNR - Daily pressure monitoring - Emergency shutdown valves installed at some locations	Prevent Detect Mitigate	Operational reliability	Financial	2	3							One RR only	MP-01: Asset	2021-06-11
2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											223	LUG	FINAL	193	[redacted]	Wes Armstrong	[redacted]					mitigate mitigate	Terrorism & asset security	Financial	1	6							One RR only	MP-06: Security	2021-06-23
2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											224	LUG	FINAL	194	Improper well abandonment	Wes Armstrong	An improper well abandonment outside of reservoir but within DSA (designated storage area) was not identified.	Missing, incorrect or incomplete records	An improper well abandonment outside of reservoir but within DSA (designated storage area) was not identified.	Financial consequence	- Well and abandonment files used to determine the condition of well abandonment. - Only operating up to 80 percent of fracture closure pressure and fracture gradient.	Detect Prevent	Operational reliability	Financial	2	4							One RR only	MP-01: Asset	2021-06-15
2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											226	LUG	FINAL	197	Leak from an abandoned well	Wes Armstrong	Leak from an abandoned well.	Accidental release/LOC flammable gas	Degradation of well	Potential release of gas and repair cost	A leak survey of abandoned wells is being developed	Detect	Operational reliability	Financial	2	4							One RR only	MP-05: Integrity	2021-06-11
2. Pipeline transportation of natural gas	2.4. Storage	2.4.1. Pool	2. Ontario Transportation											227	LUG	FINAL	199	The caprock fails due to high pressure in reservoir	Wes Armstrong	The caprock fails due to high pressure in reservoir	Operate beyond allowable limits	High pressure in reservoir	Caprock failure impacting operation	- Operational limits, equipment capabilities. - Only operating up to 80 percent of fracture gradient	Prevent Prevent	Operational reliability	Operational	1	6							One RR only	MP-05: Integrity	2021-06-11
2. Pipeline transportation of natural gas	2.4. Storage	2.4.1. Pool	2. Ontario Transportation											230	LUG	FINAL	202	The reservoir pressure exceeds fracture pressure	Steve Pardy	The reservoir pressure exceeds fracture pressure	Operate beyond allowable limits	Equipment failure or human error	Potential damage to reservoir leading to financial impact	- Pressure control at the remote compressor station as well as Dawn. - Pressure monitoring alarms at the remote compressor station as well as Dawn. - Only operating up to 80 percent of fracture gradient	Prevent Detect Prevent	Operational reliability	Financial	1	6							One RR only	MP-05: Integrity	2021-06-09
2. Pipeline transportation of natural gas	2.4. Storage	2.4.1. Pool	2. Ontario Transportation											231	LUG	FINAL	203	PMOP is incorrectly determined.	Steve Pardy	PMOP is incorrectly determined.	Design error	Human error	Potential impact operation	Two people check calculation. Only operating up to 80 percent of fracture gradient	Prevent	Operational reliability	Operational	1	3							One RR only	MP-05: Integrity	2021-06-09
2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											25	LGD	FINAL	204	Well or pool integrity issues	Steve Pardy	Loss of integrity of wells and/or pools. Gas could potentially migrate and ultimately releases to atmosphere leading to green house gas emission and/or contamination of ground water . In the very unlikely event, there could be well blowout leading to significant H&S impact and Environmental impact.	Accidental release/LOC flammable gas	Loss of containment due to various causes **NOTE:** It is very unlikely to fracture cap rock by operating above fracture gradient as natural gas wells are operating at 25% below fracture gradient and significant higher pressure than 1 psi per foot is required to fracture cap rock. Therefore, the likelihood of operating pressures during injection operations inadvertently exceed max pressure leading to fracture of cap rock is very low. Also the injection pressure is usually limited by the capability of our compressors and subsequently operating lower than the fracture pressure . 3rd party inadvertently drilling into the pool is also very unlikely for the following reasons. As our storage pools are developed , a designated storage area is mapped out to protect our reservoir from drilling. No one is allowed to drill in DSA. If someone requests to drill within 1.6 km our DSA, the Ministry of Natural Resources needs to notify the company for permission to do so. Also company personnel are constantly out at storage pool, hence unauthorized drilling activities are likely to be detected. There are naturally occurred faults but they are sealed hence it is very unlikely to loss gas through faults.	Gas could migrate outside the reef, potential contamination of ground water, which could enter houses. In rare event, there is potential for well blowout. Note : The key risk drivers are rare health and safety events (same rankings) - 1) Very rare event of gas migration outside the reef, getting into someone's house, leading to fire / explosion 2) Very rare event of well blowout, leading to fire / explosion	- Inspection : Visual Inspection - Physically attend each wellsite and check for leaks, corrosion; Check corrosion inhibitor level - Casing Inspection Logs: Physical Inspection of Casing - Storage downhole integrity management program - Cathodic protection on LUG wells (i.e. Casing potential profile logs to check CP to see how much current at casing) Note : Tecumseh doesn't have CP downhole - Emergency Processes in various manuals - C&M, EH&S, and ERP (Emergency Response Plan) - Operating standards for underground storage - Environment incident guide - Pool Operations - Reservoir Studies - Reservoir Risk Assessments - Operating at 25% below fracture gradient (i.e. 0.76 psi per foot) - Designated storage area and buffers	Prevent Prevent Prevent/Detect Prevent Mitigate Prevent/Detect Detect Prevent Prevent Prevent Prevent Prevent	Public safety	Health & Safety	2	6							**Risk Scenario 1 : Very rare sizeable leak where gas could migrate outside the reef** Financial - Significant event leading to repair cost and cost of incident : L2C4 Low Reputational - If it gets into someone's house and/or contaminating ground water, potential compliance issues and media attention : L2C4 Low H&S (less severe impact) - Potential contamination of ground water (e.g. some's wells) or people are exposed to (breathing in) natural gas (not include fire / explosion) L2C3 Low **Risk Scenario 2 : In case of very rare event, there could be well blowout** Financial - Significant financial impact : L2C5 Medium H&S (less severe impact) - Public could be exposed to natural gas (gas plume, exclude fire / explosion) L2C3 Low	MP-05: Integrity	2021-06-15

Current ID	First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version
208	2. Pipeline transportation of natural gas	2.4. Storage	2.4.1. Pool	2. Ontario Transportation											234	LUG	FINAL
209	2. Pipeline transportation of natural gas	2.4. Storage	2.4.3. Storage Aggregate	2. Ontario Transportation											235	LUG	FINAL
210	2. Pipeline transportation of natural gas	2.4. Storage	2.4.3. Storage Aggregate	2. Ontario Transportation											236	LUG	FINAL
211	2. Pipeline transportation of natural gas	2.4. Storage	2.4.3. Storage Aggregate	2. Ontario Transportation											237	LUG	FINAL
212	2. Pipeline transportation of natural gas	2.4. Storage	2.4.3. Storage Aggregate	2. Ontario Transportation											238	LUG	FINAL
213	2. Pipeline transportation of natural gas	2.4. Storage	2.4.1. Pool	2. Ontario Transportation											239	LUG	FINAL
214	2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											240	LUG	FINAL
215	2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											241	LUG	FINAL
216	2. Pipeline transportation of natural gas	2.4. Storage	2.4.1. Pool	2. Ontario Transportation											242	LUG	FINAL
217	2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											243	LUG	FINAL
218	2. Pipeline transportation of natural gas	2.4. Storage	2.4.1. Pool	2. Ontario Transportation											244	LUG	FINAL
219	2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											245	LUG	FINAL
220	2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											246	LUG	FINAL
221	2. Pipeline transportation of natural gas	2.4. Storage	2.3.3. Pipeline Aggregate	2. Ontario Transportation											247	LUG	FINAL
222	2. Pipeline transportation of natural gas	2.4. Storage	2.4.1. Pool	2. Ontario Transportation											248	LUG	FINAL
224	2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											250	LUG	FINAL
229	2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											253	LUG	FINAL
230	1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										40	LGD	FINAL
231	3. Aggregate	2.6. Aggregate	2.4.5. Transportation Aggregate	2. Ontario Transportation											40	LGD	FINAL
232	1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution			40	LGD	DRAFT						41	LGD	FINAL
233	2. Pipeline transportation of natural gas	2.4. Storage	2.4.1. Pool	2. Ontario Transportation											254	LUG	FINAL
234	2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											255	LUG	FINAL
235	2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											256	LUG	FINAL
238	2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											259	LUG	FINAL
240	2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											261	LUG	FINAL
241	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.3. Pipeline Aggregate	2. Ontario Transportation	1.13. Legacy EGD Aggregate	1.10.1. EGI Aggregate									153	LUG	FINAL
242	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.1. Transmission Main > 30% SMYS	2. Ontario Transportation											151	LUG	FINAL
243	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.1. Transmission Main > 30% SMYS	2. Ontario Transportation											152	LUG	FINAL
249	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.1. Transmission Main > 30% SMYS	2. Ontario Transportation											162	LUG	FINAL
250	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.1. Transmission Main > 30% SMYS	2. Ontario Transportation											164	LUG	FINAL
251	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.1. Transmission Main > 30% SMYS	2. Ontario Transportation											165	LUG	FINAL
254	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.1. Transmission Main > 30% SMYS	2. Ontario Transportation											173	LUG	FINAL
255	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.2. Pipeline < 30% SMYS	2. Ontario Transportation											176	LUG	FINAL
256	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.1. Transmission Main > 30% SMYS	2. Ontario Transportation											178	LUG	FINAL
257	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.1. Transmission Main > 30% SMYS	2. Ontario Transportation											183	LUG	FINAL
259	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.1. Transmission Main > 30% SMYS	2. Ontario Transportation											192	LUG	FINAL
261	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.1. Transmission Main > 30% SMYS	2. Ontario Transportation											198	LUG	FINAL
262	2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.1. Transmission Main > 30% SMYS	2. Ontario Transportation											199	LUG	FINAL
264	3. Aggregate			3. Aggregate											174	LUG	FINAL
265	3. Aggregate			3. Aggregate											187	LUG	FINAL
266	3. Aggregate			3. Aggregate											189	LUG	FINAL
267	3. Aggregate			3. Aggregate											202	LUG	FINAL

Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard	Source	Consequences
208	Improper determination of DSA (Designated storage area)	Steve Pardy	Improper determination of DSA (designated storage area)	Missing, incorrect or incomplete records	Inadequate or incorrect information on the extend of gas within the reservoir	Potential loss of revenue
209	Improper isolation when removing cross over at STO facilities	Wes Armstrong	Improper isolation when removing cross over causing release of gas	Operator errors	Improper isolation when removing cross over	Potential release of gas impacting operation
210	Incorrect fitting installed during maintenance of STO assets	Wes Armstrong	During maintenance, improper rated items may be installed due to lack of understanding and depth of knowledge of fitting rating/properties.	Installation error	During maintenance, improper rated items may be installed due to lack of understanding and depth of knowledge of fitting rating/properties	Potential compliance issue and repair cost
211	Improper rated 1/2" valve were installed on side ports of STO assets	Wes Armstrong	Improper rated 1/2" valve were installed on side ports	Installation error	Human error	Potential compliance issue
212	Improper torquing of bolts leads to leak/failure of STO assets	Wes Armstrong	Improper torquing of bolts leads to leak/failure.	Operator errors	Human error	Improper torquing of bolts leads to leak/failure, impacting operation
213	Improper torquing of casing/ cross threading of oil field	Wes Armstrong	Improper torquing of casing/ cross threading	Operator errors	Human error	Improper torquing of casing/ cross threading, impacting operation
214	A side valve of well head left open leads to leak.	Wes Armstrong	A side valve left open leads to leak.	Operator errors	Human error lead to side valve left open	Leads to leak and impact operation
215	Dropping tool down hole	Steve Pardy	Dropping tool down hole	Incorrect operation	Worker could drop a tool down the well or it could be the well-logging tool during maintenance or construction activities	Financial consequence to either retrieve a dropped tool or if it is the radioactive source for well-logging, the impacts will be more severe
216	Radio active source lost down hole	Steve Pardy	Radio active source lost down hole	Incorrect operation	Radio active source lost down hole	The well would have to be abandoned, or possibly the reservoir, leading to financial impact
217	The master valve on the well head (main isolation of the well from the gathering line) leaks	Wes Armstrong	The master valve leaks.	Equipment malfunction	The master valve leaks	Impact operation and potential leak of natural gas
218	Gas pressure exceeds burst pressure of casing of wells	Wes Armstrong	Gas pressure exceeds burst pressure of casing	Operate beyond allowable limits	Equipment malfunction or human error	Potential impact to operations and release of gas
219	The side port valve of well head leaks.	Wes Armstrong	The side port valve leaks.	Equipment malfunction	Valve leaks	Potential impact to operation
220	The wellhead seals fail.	Wes Armstrong	The wellhead seals fail.	Equipment malfunction	Wellhead seals fail	Potential impact to operation
221	The lubricator fails during wireline logging.	Wes Armstrong	The lubricator fails during wireline logging.	Equipment malfunction	The lubricator fails during wireline logging.	Potential impact to operation
222	Casing of wells (in oil field) thread of leaks	Wes Armstrong	The casing thread leaks on casing	Equipment malfunction	Casing of wells thread leaks	Cost to repair - financial impact
224	Plug failure at wellhead	Wes Armstrong	The plug fails during maintenance as it is being set, prior to wellhead being taken off	Equipment malfunction	Plug failure at wellhead during maintenance as it is being set prior to wellhead being taken off	Potential worker H&S impact
229	Lightning Strike impacting Storage Wellhead System	Wes Armstrong	Lightning strike could damage electrical distribution and controls equipment.	Natural forces/weather	Lightning	Potential fire and operating system failure
230	Lightning Strike impacting Distribution System	Murray Costello	Lightning strike could damage electrical distribution and controls equipment.	Natural forces/weather	Lightning strike to Enbridge metal assets which are connected to electrical equipment like SCADA / Telemetry controls [NOTE : Impact to gate stations: Lancaster Gate in 2015, Chalk River Gate in 2012, Brockville Gate in 2011. Generally, it affects SCADA equipment which can be sensitive to electrical surges, but consequences have been low. Damaged equipment is generally repaired quickly and lightning strikes do not generally occur during heating season.]	Impairment or damage to electrical equipment like SCADA / Telemetry controls. Could lead to immediate or latent fire or arcing.
231	Lightning Strike impacting transmission system	Wes Armstrong	Lightning strike could damage electrical and controls equipment for STO.	Natural forces/weather	Lightning strike to gas carrying assets which are connected to electrical equipment like SCADA / Telemetry controls	Impair or damage of electrical equipment like SCADA / Telemetry controls Damage to assets and ignition with potential property damage and injury/fatality Damage to assets resulting in impacts to deliver gas.
232	Lightning Strike melting PE pipe	Steve McGivery	Lightning strike could melt PE piping resulting in loss of containment	Natural forces/weather	Lightning strike to could melt PE piping [NOTE: Two past incidents of leaks in the Enbridge pipeline system have been related to lightning strikes]	Damage pipe resulting to loss of containment, potential for H&S impact
233	Extreme Cold/ winter Conditions affecting downhole operation	Steve Pardy	Extreme Cold/ winter Conditions	Natural forces/weather	Extreme Cold/ winter Conditions	Potential impact to operation
234	Forest fire at adjacent to wells	Wes Armstrong	There is a fire in the adjacent field/woods.	Natural forces/weather	There is a fire in the adjacent field/woods.	Potential impact to operation
235	Surface gas is present at the well head.	Wes Armstrong	Surface gas is present at the well head.	Natural forces/weather	Methane exists in groundwater, so there may be a release of natural gas during drilling and usually go away after a period of time	Workers could be exposed to flammable gas
238	Corrosion below master valve (main isolation of the well from the gathering line) at surface	Steve Pardy	There is corrosion below master valve at surface - leading to a leak of natural gas.	corrosion external	Corrosion below master valve at surface	Require repair and potential leak of natural gas
240	Master valve (main isolation of the well from the gathering line) erosion	Steve Pardy	There is erosion above master valve at surface.	Erosion and Sedimentation	Erosion above master valve at surface.	Require repair and potential leak of natural gas
241	3rd party damage STO pipeline	Michael McGivery	Potential for third party damage on a newly constructed STO pipeline.	3rd party damage	STO Locate Area / Ontario One Call issues, including assets outside of the 100m buffer and delays in mapping updates being sent to Ontario One Call	Damage to pipeline possibly leading to gas release or operational disruption
242	Class Location Changes in proximity of 30% SMYS pipelines	Todd Piercey	Changes in Class Location: As development occurs in the proximity of our 30% SMYS pipelines, there is potential for changes in class location which results in a potential for our pipelines not meeting the increased design requirements. This could potentially result in an increased likelihood and increased potential consequences of a line hit incident. However, the main risks identified are the regulatory and reputation risks associated with not meeting regulatory requirements..	3rd party damage	As development occurs in the proximity of our 30% SMYS pipelines, there is potential for changes in class location which results in a potential for our pipelines not meeting the increased design requirements.	Potential for our pipelines not meeting the increased design requirements. This could potentially result in an increased likelihood and increased potential consequences of a line hit incident. However, the main risks identified are the regulatory and reputation risks associated with not meeting regulatory requirements..
243	Easement Encroachment of transmission pipeline	Wes Armstrong	Easement Encroachment. Encroachment on our easement has occurred. This could potentially result in an increased likelihood of a line hit incident and non-compliance with the TSSA Code Adoption Document	3rd party damage	Encroachment on our easement has occurred.	This could potentially result in an increased likelihood of a line hit incident and non-compliance with the TSSA Code Adoption Document
249	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]
250	Dawn Trafalgar Mainline NPS 42 SCC (Stress corrosion cracking)	Ryan Werenich	Potential failure on the 42" Dawn Trafalgar Mainline due to stress corrosion cracking.	Corrosion external	42" Dawn Trafalgar Mainline due to stress corrosion cracking.	Potential line failure
251	Leak at transmission pipeline leading to gas release/explosion	Ryan Werenich	Leak leading to gas release or explosion	Accidental release/LOC flammable gas	Leaks due to integrity issue	Potential for rare fire / explosion events
254	Corrosion on Storage Pool Line	Ryan Werenich	Internal corrosion leading to leak and rupture on a storage pool line. Specific corrosion mechanism has been identified and mitigated and does not apply to the overall system.	corrosion internal	Internal corrosion	Leading to leak and rupture on a storage pool line. Note: Specific corrosion mechanism has been identified and mitigated and does not apply to the overall system.
255	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]
256	Rupture of a 30% SMYS pipeline	Mohamed Chebaro	Potential rupture of a 30% SMYS or > 30% SMYS pipeline that could result in significant consequences.	3rd party damage	These pipelines are subject to a number of threats and there have been some significant incidents within Enbridge and the industry. Anomalies found during inspection operations could be an indicator of the risk level.	Significant public safety, customer loss and financial consequences could result from a failure.
257	Improper construction practice	Michael McGivery	Improper construction practice leading to explosion, gas release, and fire/explosion	Construction defect	Improper construction practice leading to explosion, gas release, and fire/explosion	Health and Safety risk resulting in injury
259	Lack of proper documentation for welding procedures	Carrie Cook	Lack of proper documentation for welding procedures. May not have all complete and correct documentation to register welding procedures.	Construction defect	Lack of proper documentation for welding procedures. May not have all complete and correct documentation to register welding procedures.	Potential compliance issue
261	Failure of single feed systems (Transmission line) leading to significant loss of customer	Tracey Teed Martin	Failure of critical single feed could lead to significant loss of customer. e.g. Guelph Lateral only tied into 1 section of Dawn Trafalgar, the 26". There could be nearly 50,000 customers lost if the pipeline has to be taken completely out of service. The city of Cambridge is fed primarily from a single line. The city of Trenton is primarily fed from a single line. There are numerous others as well.	Loss of upstream feed	Loss of single feed	significant loss of customer
262	Potential spill or leak from a Pipeline Buried Drip vessel	Wes Armstrong	Potential spill or leak from a Pipeline Buried Drip vessel	Degradation	Leak from pipeline drip vessel due to corrosion Note : The concern is these vessels are seeing the pipeline pressure and collecting possible liquids while pigging and never been inspected	Leak repair resulting in disruption to operations
264	Casings short to pipe and corrode pipe	Steve Pardy	Casings short to pipe and corrode pipe - ability to control corrosion is more difficult on casing pipe, also don't know where all the casings are)	Corrosion external	Casings short to pipe and corrode pipe - ability to control corrosion is more difficult on casing pipe, also don't know where all the casings are)	Corrosion remediation or replacement of asset resulting in disruption to operations
265	Installation of Company owned gas piping causing damage to other utility	Steve McGivery	Our installation caused damage to third party utility (i.e.. Gas line, water line, sewer line, propane line)	Contact with buried underground services	Unknown non-located underground infrastructure on private property	employee/contractor injury or public (home-owner) injury and property damage
266	Insufficient dewatering after construction of new pipeline	Ryan Werenich	Insufficient dewatering after construction of new pipeline. Water left in the line could cause regulator freeze-off. Could also hinder the ability to properly odourize.	Construction defect	Insufficient dewatering after construction of new pipeline.	Water left in the line could cause regulator freeze-off. Could also hinder the ability to properly odourize.
267	Inadequate or lack of inspection of underwater pipelines	Ryan Werenich	Non-compliance to Z662 10.6.4 regarding diving inspections at underwater pipelines. Some dives are too difficult to complete or are not able to provide worthwhile data.	incorrect operation	Underwater crossings that have not been properly identified in records and in inspection programs	reputation damage due to a non-compliance related to inspecting underwater crossings

Current ID	Controls	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region
208	- 3D Seismic Interpretation - Obtain additional lands to act as buffer and reduce this risk. - 1.6 km buffer around the DSA - Monitor pressure inventory relationship in reservoir - Operator's round (report pressures to Ministry of Natural Resources)	Prevent Prevent Prevent Detect Detect	Operational regulation	Financial	3	4		
209	-Procedures, experienced operators - crossover blown down before removing any bolts. - Lock-out tag-out	Prevent, Detect, Mitigate Prevent Prevent	Operational reliability	Operational	1	4		
210	- procedures, BOM documentation - GPI, quarterly and annual audits. - most API rating components won't physically fit if they are not properly rated	Prevent Detect Prevent	Operational regulation	Reputational	3	3		
211	BOM, Operator experience.	Prevent	Operational regulation	Reputational	3	3		
212	A third party contractor torques all the bolts and supplies report.	Prevent	Operational reliability	Operational	1	2		
213	Standard practices of the oil field for handling and running of casing are followed as per API RP 5C1. Drilling program	Prevent, Detect	Operational reliability	Operational	3	2		
214	Bull plug, operator on site and should be able to hear gas escaping.	Prevent, Detect	Operational reliability	Operational	1	2		
215	Procedures, wireline and equipment inspection before operation	Prevent	Operational reliability	Financial	1	5		
216	Procedures, Gage bar run, Wire line condition check before operation. Insurance.	Prevent	Operational reliability	Financial	1	6		
217	- Engineering design - Regulated maintenance - Programmed maintenance procedures - Integrity management program	Prevent Prevent, Detect Prevent Prevent, Detect	Operational reliability	Operational	5	3		
218	- There are operating limits at each station. - The Integrity Management Program requires inspection of each well once every 5-10 years.	Prevent Detect	Operational reliability	Operational	1	4		
219	Maintenance program, Inspections. Valves generally do not fail completely at once. Gas would be unodourized. Low populated areas, gas does have "natural smell" from being in the downhole. There would likely be an audible sound.	Prevent & Detect	Operational reliability	Operational	3	2		
220	Maintenance program. Gaskets fail gradually starting with a small leak. The odour of gas in wells alert people, even when the leak is very small.	Prevent & Detect	Operational reliability	Operational	4	2		
221	Use of BOP allows control of the well. The master valve can also shut off the gas.	Prevent & Mitigate	Operational reliability	Operational	1	4		
222	Standard practices of the oil field for handling and running of casing are followed as per API RP 5C1 Pressure test of casing prior to drilling out cement plug	Prevent, Detect	Operational reliability	Financial	4	3		
224	Hydromite setting on top of plug BOP, water column, Hydromite setting procedure	Prevent, Detect	Workforce safety	Health & Safety	4	2		
229	- The well is grounded. - The valves and piping would not be affected by lightning strike. if there were electrical components on the valve they would likely have to be replaced	Prevent Mitigate	Operational reliability	Operational	1	2		
230	- Gas Control monitored alarms and pressure sensors to alert of emergency conditions - Backup power generation systems - Contingency plans to operate in absence of SCADA systems - EM (emergency Management) exercises - Contingency plans (network) - Business Continuity Management (BCM) Program - Backup communications in absence of SCADA - ERP - emergency Response Plan - Ground grid - Surge protection - Polyphaser on communication cables - Isolators	Detect Mitigate Mitigate Mitigate Detect Mitigate Mitigate Mitigate Mitigate Mitigate	Operational reliability	Operational	4	2		
231	275. Gas Control monitored alarms and pressure sensors to alert of emergency conditions 273. Backup power generation systems 274. Contingency plans to operate in absence of SCADA systems (MP-08) 267. MP Manuals 268. EM (Emergency Management) exercises 269. Contingency plans 270. Business Continuity Management (BCM) Program Lightning rods (in a few locations), grounding, emergency call out /procedures	Detect Mitigate Mitigate Mitigate Detect Mitigate Mitigate Mitigate Mitigate	Operational reliability	Operational	4	2		
232	Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan)	Mitigate	Public safety	Health & Safety	4	4		
233	All materials are designed to -50 degrees Celsius	Prevent	Operational reliability	Operational	1	2		
234	Buffer zone created when drilling the well, by the well pad itself, and maintenance of the site. The fire does not create the heat required for a major storage gas incident - a pipeline rupture is not imminent. The gaskets on the well are not flammable.	Prevent	Operational reliability	Operational	4	2		
235	Wells are located in an open area. There is no location for gas to collect.	Prevent, Mitigate	Workforce safety	Health & Safety	5	1		
238	- Casing Inspection logs - Well Maintenance Programs - Cathodic protection program - Casing potential profile logs	Detect Prevent, Detect Prevent Detect	Operational reliability	Financial	3	4		
240	- Casing inspection Log - Erosional velocity study, SOP 7200-13	Detect Prevent, Detect	Operational reliability	Financial	2	2		
241	STO has a locate zone for existing Pipelines in Ontario One Call. The STO zone is identified so when a ticket comes through OOC to notify the proper group (LSP, Union Gas STO etc.) for the locate to be performed. The issue is that STO facilities are not tagged as such in the GIS Proposed & As Constructed states. Standard for completions of as-builts once records have been received for a constructed is 90 days. Current LUG Controls: - Proposed projects are marked in GIS prior to construction commencing. If proposed assets are outside of the 100m buffer a new buffer bubble will be added. - Mapping update sent to Ontario One Call. Update sent with monthly LUG gas distribution mapping update LUG & LEGD Controls: - In-field construction - As-built asset survey and GIS update - Mapping update sent to Ontario One Call	Prevent Detect Mitigate Detect Mitigate	Public safety	Health & Safety	1	6		
242	- Damage prevention program - Call b4 you dig - Plant Damage Prevention procedures in section 10 of DOM - Emergency Response Program - Integrity Program - Annual Class Location Survey	Prevent, Detect, Mitigate Prevent Prevent Mitigate Detect Detect	Operational regulation	Reputational	3	5		
243	- Damage prevention program - call b4 you dig, - Plant Damage Prevention procedures in section 10 of DOM - ERP - Integrity Program - Easement encroachment standard now contained in integrated standard under CMP	Prevent, Detect, Mitigate Prevent Mitigate Prevent Detect Detect	Operational regulation	Reputational	1	6		
249	[redacted]	Prevent Mitigate	Operational reliability	Operational	3	5		
250	In-line inspection response criteria, Emergency Response Program	Prevent, Detect Mitigate	Public safety	Reputational	1	6		
251	- Corrosion control program, cathodic protection - coated pipe - surveys (SOP) - Integrity Program	Prevent Prevent Detect Prevent, Detect	Public safety	Operational	5	2		
254	- Data Collection and Pre-assessment of STO Pool Lines. - Investigative Digs on Sombra Pool Line. Note : Initial report suggests non-aggressive corrosion rate.	Detect Prevent, Detect	Operational reliability	Financial	1	4		
255	[redacted]	Prevent Detect Prevent Prevent Prevent Mitigate Prevent, Detect Mitigate	Operational reliability	Reputational	4	6		
256	- Pipeline Asset Integrity Management Program that includes In-line Inspection Tools and, response criteria - the External Corrosion Direct Assessment Process - Emergency Response Program -Continue to evaluate higher risk TIMP lines through Safety Case Program to validate assessments and methodologies	Prevent Prevent Detect Mitigate Detect	Public safety	Health & Safety	5	5		
257	CMP, QA program, C&M manual, POW's, inspection, CAP	Prevent Detect Mitigate	Public safety	Health & Safety	1	6		
259	CAP, QA program	Prevent, Detect	Operational regulation	Reputational	1	3		
261	- Damage prevention program - Call b4 you dig, locates - Common Ground Alliance - Plant Damage Prevention procedures in section 10 of DOM - ERP - Valve inspections	Prevent Prevent Prevent Prevent Mitigate Prevent, Detect	Operational reliability	Operational	2	7		
262	ERP (Spill response)	Mitigate	Operational reliability	Operational	3	4		
264	Corrosion control manual Integrity Manual Gas Storage Manual	Prevent, Detect	Operational reliability	Operational	6	3		
265	Added Pre-work any conversion installations because locates are not available -prework form for customer/property owner to confirm if there was private infrastructure and to ensure they understood they were accountable to provide the location of these assets: both 2 & 3 page forms can be found on the forms page (Canada East - Online Forms (enbridge.com)) under Form # 10134. The accountability for private utilities is clarified in the legislation – i.e. property owners responsible for utilities on private property (https://ontarioonecall.ca/private-locates/). -daylight all known utilities, property/land owner to notify utility owners if unlocated utilities are found -ERP	Prevent Prevent Prevent Mitigate	Public safety	Health & Safety	4	5		
266	CMP, C&M manual, POW's, inspections	Prevent, Detect	Operational reliability	Operational	5	4		
267	Integrity program, ERP. , Non-compliance process	Prevent Mitigate	Operational regulation	Reputational	3	3		

Current ID	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
208					One RR only	MP-05: Integrity	2021-06-25
209					One RR only	MP-01: Asset	2021-06-11
210					One RR only	MP-01: Asset	2021-06-11
211					One RR only	MP-01: Asset	2021-06-11
212					One RR only	MP-01: Asset	2021-06-11
213					One RR only	MP-01: Asset	2021-06-11
214					One RR only	MP-01: Asset	2021-06-11
215					One RR only	MP-05: Integrity	2021-05-31 by M. Hildebrand - following email confirm tion from Steve Pardy May 30, 2021.
216					One RR only	MP-05: Integrity	2021-06-09
217					One RR only	MP-05: Integrity	2021-06-11
218					One RR only	MP-01: Asset	2021-06-11
219					One RR only	MP-01: Asset	2021-06-11
220					One RR only	MP-01: Asset	2021-06-11
221					One RR only	MP-01: Asset	2021-06-11
222					One RR only	MP-05: Integrity	2021-06-11
224					H&S: Low L1 C5	MP-01: Asset	2021-06-11
229					One RR only	MP-05: Integrity	2021-06-11
230				November 10, 2021 - Matched wording of ID #230 and 231	One RR only	MP-05: Integrity	2022-06-13
231				November 10, 2021 - Matched wording of ID #230 and 231 - Storage Wells wording removed Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023	Medium: Operational, L5 C3 Low: Financial, L1 C2 Low: Operational, L1 C2	MP-01: Asset	2023-02-28
232					L1 C2 Financial (Low)	MP-02: Emergency	7/4/2022
233					One RR only	MP-05: Integrity	2021-06-09
234					One RR only	MP-05: Integrity	2021-06-11
235					One RR only	MP-01: Asset	2021-06-11
238					One RR only	MP-05: Integrity	2021-06-09
240					One RR only	MP-05: Integrity	2021-06-09
241	Long Term Treatment Plan: Harmonized GIS platform across all of EGI (expected to be several years out); Short Term: -Proposed solution is to adopt a process inline with the LUG STO process due across all of EGI to account for proposed assets outside of the buffer and delays in mapping updates being sent to Ontario One Call. Impacts on any other in-progress process/ integration activities and look to prevent cascading impacts/ scope creep need to be considered.	Michael Abate, Michael Cromwell	2024 Long Term		Reputation L3C3 Low Operational C2L3 Low	MP-07: Damage Prevention	2021-01-15
242					One RR only	MP-01: Asset	2021-06-28
243					One RR only	MP-01: Asset	2021-06-11
249					One RR only	MP-06: Security	2021-06-07
250	Dig Program has found low levels of stress corrosion cracking. EMAT run form 2019 indicates absence of SCC cracks of significant concern. DNV (consultant)has been involved in growth and modelling studies The Trafalgar 42 is also in the process of being integrated into PiMSlider and the Risk Model. This will provide better visibility into the overall risk due to compounding threats, however the SCC threat in the risk model is in the process of being updated and improved by IA. The Engineering Assessment was provided to IA to support these improvements. EMAT tentatively scheduled for 2024.	Erin Wishart	2024	Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2023-08-01
251				Risk Owner Updated from A.S. August 1, 2023	Medium: Low L1 C6	MP-05: Integrity	2023-08-01
254	Launcher receiver to be installed inv no.: 1271 to allow for bi-annual cleaning pig operations Ultra high resolution MFL ILI tool run planned to better detect pin hole features.	Paul Hammell	2023	Risk Owner Updated from A.S. August 1, 2023	One RR only	MP-05: Integrity	2023-08-01
255	Preferred treatment plan requires elevation following New Risk Endorsement	Jeff Cadotte	Proposed in-service date: 2025	[redacted]	L3 C5 (Regulatory), L4 C5 (Environmental), L4 C5 (Financial), L3 C5 (Customer Loss), L2 C4 (H&S)	MP-01: Asset	2023-01-31
256	Advance and refine the Pipeline Integrity Management Program through: implementation of IMP Evolution activities (IAIR - Independent Asset Integrity Review) to reduce data uncertainty on TIMP system. Assessment of rupture threat for all TIMP pipelines (>30% SMYS) due to corrosion, manufacturing, SCC, and TPD and evaluation of risk against safety targets (Annex O Reliability Target)	Ryan Werenich	2027	treatment plan update 5/1/2023 Q4 Update: - Hydrotechnical and geotechnical standards have been developed.	One RR only	MP-05: Integrity	2023-01-31
257					Operational: L3 C5 Medium, L5 C3 Medium H&S: L1 C6 Medium	MP-01: Asset	2021-06-23
259					One RR only	MP-01: Asset	2021-06-29
261				Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
262					One RR only	MP-05: Integrity	2021-06-28
264					One RR only	MP-05: Integrity	2021-06-25
265					One RR only	MP-01: Asset	7/4/2022
266				*May 25, 2023 - Integrity identified this needs new risk ownership (pipelines or construction)	One RR only	MP-01: Asset	2023-08-01
267				Risk Owner Updated from A.S. August 1, 2023	One RR only	MP-05: Integrity	2023-08-01

First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version	Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard	Source	Consequences	Controls	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										150	EGI	FINAL	269	Sewer Crossbore	Mohamed Chebaro	Sewer Lateral Crossbore Damage. EGI (LUG & LEG) has installed natural gas pipe through sewer using trenchless technology (i.e. directional drilling). Pipe is compromised when sewer line gets cleaned or visually monitored.	3rd party damage	Incomplete records	Gas line can become compromised when sewer line gets cleaned with cutting tool of high pressure water jet potentially leading to a sudden release of natural gas and potential migration to building(s) by direct path through sewer. Potentially resulting in building explosion, if LEL is reached and an ignition source is present, with potential for multiple fatalities (Public H&S impact and service disruptions).	- Sewer Safety Program - Call before you clear/proactive investigation projects and locate process - Emergency processes in various manuals - C&M, Sewer Safety, EPM (Emergency Procedures Manual) - Communication with plumbing companies -Cross bore probability and risk tool to support prioritization of legacy sewer safety inspection projects -Current construction practices aligned with industry leading practices ensuring new cross bores are not created	Prevention Detection Mitigation	Public safety	Health & Safety	4	6			**Short term:** Evaluate acoustic inspection technology for identifying legacy cross bores Evaluate feasibility of installation plan requirement for contractors **Ongoing Treatment:** Complete annual proactive inspections Execute Sewer Lateral Cross Bore Program	Wendy McDowell	Ongoing	treatment plan & control update 06/13/2023 Q4 Updates: -Planned Q1 2023 start date for acoustic evaluation -6,002 sewer and storm lateral inspections completed YTD -2,759 addressed cleared of cross bores YTD		MP-05: Integrity	2023-01-31
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										52	LGD	FINAL	274	Non-Vital Pipeline : 3rd Party Damages	Michael McGivery	Underground non-vital pipeline could be damaged due to 3rd party excavation activities. This could impair condition of assets and lead to potential release of natural gas, subsequently increase in green house gas emission, potential H&S impact to public and service disruption **Context :** Risk Evaluation Approach - Consequence ranking is based on single event. Likelihood ranking of the event was based on the entire population of non-vital pipeline system taking into consideration of existing controls and other factors leading to the specific consequence. For the integrated company, there are approximately 2500 damages per year. NOTE: Sewer Crossbore and Compression Coupling risks are addressed as separate risk entries in the risk register. Hence, they are excluded from this evaluation.	3rd party damage	-3rd parties are unaware of location of underground pipeline, subsequently damage pipeline during activities. - Inappropriate methods used to excavation in the vicinity of natural gas facilities could increase potential of pipe damage. - Locate Service Provider (LSP) could have difficulty to access current records in timely manner. In ability to access records would delay issuance of locate, subsequently excavator may conduct work without locate. There is also potential for LSP to interpret records incorrectly. - Mains or services are installed during the valid period of a locate (60 days) and contractor is not aware of them, conduct construction activities around the new pipes, subsequently damage the pipe - Ontario One Call could fail to / inaccurately / delay in process locate requests to the Locate Service Provider which subsequently lead to lost calls, failure to / inaccurately to / delay to process tickets. This could potentially lead to excavation damages to underground assets and customer dissatisfaction.	Gas release, venting to atmosphere : Release of natural gas, subsequently increase in green house gas emission and potential interruption of services, with remote chance of flammable gas event leading to H&S impact NOTE : Risk driver is reputational risk, referring to media coverage (Local media coverage is referring to major news outlet such as CP24)	Engineering Design 1) Minimum DOC requirement 2) Excess Flow Valve installed at service connection (for new services) 3) ST-1C-A2AC-3AF4 HCA and Class Location Design Standard Operation Standard / Manuals 1) ST-19-F880-F526 Class Location Operating Standard 2) ST-18-A14C-36FF Depth of Cover Operating Standard, ST-17-A1C8-8CE9 Pipeline Markers Operating Standard (For some non-vital mains, especially those in remote locations) 3) Emergency Processes in various manuals - C&M, CS&C, EH&S and ERP (Emergency Response Plan) MP-07 Manuals (These are use for external parties): 1) Third Party Requirements in the Vicinity of Natural Gas Pipelines, CGA Best Practices Guides for Damage Prevention & Safety Processes (Currently operating with formal document integration in-development), these are GDS facing processes: 2) Locate Request - Public ROW Process (Sticker locates), Locator Support Process, Records Support Process, DP Quality Management Process 3) Pipeline Patrol Process 4) Competency Management Process, Crossing and Encroachment Authorization Process (Permit applies to CER assets and some STO assets), Public Awareness Process 5) Land Use and Ownership Monitoring Process (Tie to HCA assets, asset types of buildings and who own them and asset types of risks) 6) Third Party Observation Process (Apply to all Transmission / Vital Mains and discretionary for DO assets) MP-03 Notification to TSSA through Spills Action Center (SAC) Public Affairs & Ombudsman office Standard media protocols	Eng. Design 1) Prevent 2) Mitigate 3) Prevent / Detect Opt Std / Manuals 1) Prevent / Detect 2) Prevent 3) Mitigate MP-07 1) Prevent 2) Prevent 3) Prevent / Detect 4) Prevent 5) Detect 6) Prevent MP-03 Detect / Mitigate PA&O office Mitigate	Public safety	Reputational	7	3			A series of initiatives which are enhancements and expansions of existing controls focused on preventing damages	Michael Abate	N/A	07/19/2022, Ongoing monitoring of existing controls and associated metrics to determine adjustments as appropriate (Q4 2022) Q4 Updates: - reverted timeline to N/A	- Financial (Based on cost for repair - gas cost, labor, material, equipment and resource time): L7C1 Medium - Health & Safety (Based on H&S impact to the 3rd party who damages the pipe) : L5C3 Medium - Environment (Based on damages to surface gravel or soil within an Enbridge facility; able to be remediated by trained personnel quickly and effectively) : L7C2 Medium Operational (Based on outage and resource diversion. Expected a couple of crews would be required to make safe) : L7C2 Medium	MP-07: Damage Prevention	2023-01-31
3. Aggregate			3. Aggregate			33	LGD							33	LGD	FINAL	275	Vital Pipeline - 3rd Party Damages	Michael McGivery	Underground vital mains could be damaged due to 3rd party excavation activities. This could impair condition of assets and lead to potential release of natural gas, subsequently increase in green house gas emission, potential H&S impact to public and service disruption **Context :** Risk Evaluation Approach - Consequence ranking is based on single event. Likelihood ranking of the event was based on the entire population of non-vital pipeline system taking into consideration of existing controls and other factors leading to the specific consequence. NOTE: Sewer Crossbore and Compression Coupling risks are addressed as separate risk entries in the risk register. Hence, they are excluded from this evaluation.	3rd party damage	-3rd parties are unaware of location of underground pipeline, subsequently damage pipeline during activities. - Inappropriate methods used to excavation in the vicinity of natural gas facilities could increase potential of pipe damage. - Locate Service Provider (LSP) could have difficulty to access current records in timely manner. In ability to access records would delay issuance of locate, subsequently excavator may conduct work without locate. There is also potential for LSP to interpret records incorrectly. - Mains or services are installed during the valid period of a locate (60 days) and contractor is not aware of them, conduct construction activities around the new pipes, subsequently damage the pipe - Ontario One Call could fail to / inaccurately / delay in process locate requests to the Locate Service Provider which subsequently lead to lost calls, failure to / inaccurately to / delay to process tickets. This could potentially lead to excavation damages to underground assets and customer dissatisfaction.	Gas release, venting to atmosphere : Release of natural gas, subsequently increase in green house gas emission and potential interruption of services, with remote chance of flammable gas event leading to H&S impact NOTE: There are multiple risk drivers : Financial, H&S to public, Operational and Reputational Impacts	Engineering Design 1) Minimum DOC requirement 2) Excess Flow Valve installed at service connection (for new services) 3) ST-1C-A2AC-3AF4 HCA and Class Location Design Standard Operation Standard / Manuals 1) ST-19-F880-F526 Class Location Operating Standard 2) ST-18-A14C-36FF Depth of Cover Operating Standard, ST-17-A1C8-8CE9 Pipeline Markers Operating Standard (For some non-vital mains, especially those in remote locations) 3) Emergency Processes in various manuals - C&M, CS&C, EH&S and ERP (Emergency Response Plan) MP-07 Manuals (These are use for external parties): 1) Third Party Requirements in the Vicinity of Natural Gas Pipelines, CGA Best Practices Guides for Damage Prevention & Safety Processes (Currently operating with formal document integration in-development), these are GDS facing processes: 2) Locate Request - Public ROW Process (Sticker locates), Locator Support Process, Records Support Process, DP Quality Management Process 3) Pipeline Patrol Process 4) Competency Management Process, Crossing and Encroachment Authorization Process (Permit applies to CER assets and some STO assets), Public Awareness Process 5) Land Use and Ownership Monitoring Process (Tie to HCA assets, asset types of buildings and who own them and asset types of risks) 6) Third Party Observation Process (Apply to all Transmission / Vital Mains and discretionary for DO assets) MP-03 Notification to TSSA through Spills Action Center (SAC) Public Affairs & Ombudsman office Standard media protocols	Eng. Design 1) Prevent 2) Mitigate 3) Prevent / Detect Opt Std / Manuals 1) Prevent / Detect 2) Prevent 3) Mitigate MP-07 1) Prevent 2) Prevent 3) Prevent / Detect 4) Prevent 5) Detect 6) Prevent MP-03 Detect / Mitigate PA&O office Mitigate	Public safety	Health & Safety	3	6							- Financial (Based on repair cost of an average damage): L6C3 Medium - Environment (Ranking based on estimated area being impacted following a potential damage) : L3C3 Low Operational (Based on outage and resource diversion. Expected a couple of crews would be required to make safe) : L3C5 Medium - Regulatory (Based on evacuation and regulatory impact - e.g. CER) : L3C4 Medium	MP-07: Damage Prevention	2021-06-15
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									161	LUG	FINAL	278	[redacted]	Steve McGivery	[redacted]					Prevent Mitigate	Operational reliability	Operational	3	5							One RR only	MP-06: Security	7/4/2022
1. Natural gas distribution	1.1. Pipe	1.1.4. Pipe Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									167	LUG	FINAL	280	Main leak repair	Tara Kuuskman	Leak on main leading to gas release	Corrosion external	Leak from pipeline due to external corrosion	Operational interruption to complete repair	Damage prevention program, call b4 you dig, locates, Common Ground Alliance, ERP, Valve inspections	Prevent, detect, Mitigate	Operational reliability	Operational	7	2						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2021-06-25
1. Natural gas distribution	1.1. Pipe	1.1.4. Pipe Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									168	LUG	FINAL	281	Main leak ignited release	Tara Kuuskman	Leak on main leading to explosion	Corrosion external	Leak from pipeline due to external corrosion resulting in ignition	Potential for rare fire / explosion events	Corrosion control program, coated pipe, cathodic protection, surveys (SOP), Integrity Program (leakage tracking tool)	Prevent, detect, Mitigate	Public safety	Health & Safety	1	6						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2021-06-28
1. Natural gas distribution	1.1. Pipe	1.1.4. Pipe Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate										169	LUG	FINAL	282	Leak on bare/unprotected pipe leading to a gas release	Tara Kuuskman	Leak on bare/unprotected pipe leading to a gas release	Corrosion external	Corrosion of steel pipes which are unprotected or no coating (bare steels)	Leading to leaks and gas release	Leak surveys (SOP) completed on a semi-annual basis and quarterly if pipe located in a "wall to wall" area	Detect	Operational reliability	Operational	7	2			Program to replace in AMP	Taylor Jones	2021-2024 as per 2021-2025 asset plan Table 5.2-5	Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2021-06-03
1. Natural gas distribution	1.1. Pipe	1.1.1. Distribution Main	1. Ontario Distribution	1.12. Legacy UGL Aggregate										170	LUG	FINAL	283	Leak on a LP or MIP (Modified Intermediate Pressure) main	Tara Kuuskman	Leak on a LP or MIP main	Corrosion external	External corrosion	Leaks and release of gas	Leak surveys (SOP) completed on a semi-annual basis and quarterly if pipe located in a "wall to wall" area	Detect	Operational reliability	Operational	5	3						Risk Owner updated from A.S on August 1, 2023		MP-05: Integrity	2021-06-11
1. Natural gas distribution	1.3. Customer asset	1.3.2. Residential Meter	1. Ontario Distribution	1.14. EGI Aggregate										175	LUG	FINAL	286	Field applied coating failure	Tara Kuuskman	Flowering of tape coat on riser at residential meter sets. Could lead to corrosion of pipe and a gas release.	Corrosion external	Flowering of tape coat on riser at residential meter sets.	Could lead to corrosion of pipe and a gas release.	inspections, corrosion control program	Detect, Prevent	Operational reliability	Reputational	5	3						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2021-06-25
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										Updated 2019	EGI	FINAL	288	Compression Couplings Geotechnical Threats	Tracey Teed Martin	Pipes that are connected by couplings could shift due to frost/soil movement, which could lead to a leak requiring a repair. Worst case is full pullout separation failure. Mechanical fittings and mechanical tees are found in GIS and tracked and monitored. The leak surveys will likely catch the leak before it escalates.	Geotechnical threats	Frost heave or any type of ground movement (wash out) near CC & 45 deg elbow on low depth of cover pipelines	Leak may burst through soil and release above grade leading to flammable dispersion resulting in potential fire OR Leak may migrate underground (from service or main) to building leading to possible build up to flammable atmosphere and potentially ignite resulting in possible explosion (same RR)	1. Emergency response procedures by-pass and assumption that there is potential for a CC to exist 2. Records check CCI before work starts 3. Tacit knowledge of area to identify locations where CC may exist 4. Leak surveys 5. Gas is odourized for leak detection	Prevent Detect Prevent Detect Detect	Public safety	Health & Safety	3	5						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	Worker Safety H&S C5, L2, RR M Unrestrained - Financial C3, L6, RR M Restrained Lug and Rod - Financial C1, L6, RR M Aerial Crossings debris issue H&S C5, L1, RR L	MP-07: Damage Prevention	6/20/2022
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										Updated 2019	EGI	FINAL	289	Compression Couplings Excavation Threats	Michael McGivery	Pipes that are connected by couplings could detach during construction work or as a result of third party damage, leading to a safety concern. Mechanical fittings and mechanical tees are found in GIS and tracked and monitored. The leak surveys will likely catch the leak before it escalates. Worst case is full pullout separation failure.	3rd party damage	3rd, 2nd, or 1st party excavation in vicinity of CC and point of thrust due to inadequate locate, due to failure of 3rd party to order locates, or excavation procedure - missing or incomplete Company records (e.g. field notes, missy tickets, as laid drawings, etc.)	Above ground leak leading to flammable dispersion resulting in potential fire OR Latent leak due to a previous excavation/backfill resulting in potential migration into building resulting in possible explosion (same RR)	1. Emergency response procedures by-pass and assumption that there is potential for a CC to exist 2. Records check CCI before work starts 3. Tacit knowledge of area to identify locations where CC may exist 4. Leak surveys 5. Gas is odourized for leak detection	Prevent Detect Prevent Detect Detect	Public safety	Health & Safety	2	6						1 workshop and 1 stakeholder focus group discussion in Dec 2022 & determination of excavator specific risk treatment plans with documentation in progress	One RR only	MP-07: Damage Prevention	2023-01-30
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										New 2019	EGI	FINAL	290	Compression Couplings Integrity Concerns - Fasteners	Tara Kuuskman	Degradation of compressions coupling fasteners over time could potentially lead to a leak from circumference of fitting - partial separation due to corrosion / degradation over time may also become a full separation	Degradation	Corrosion on bolts holding CC together	Leak may burst through soil and release above grade leading to flammable dispersion resulting in potential fire OR Leak may migrate to nearby building or utility and potentially build up to LEL indoors resulting in potential explosion	1. Emergency response procedures by-pass and assumption that there is potential for a CC to exist 2. Records check CCI before work starts 3. Tacit knowledge of area to identify locations where CC may exist 4. Leak surveys 5. Gas is odourized for leak detection	Prevent Detect Prevent Detect Detect	Public safety	Health & Safety	3	5				Fred Butrico		Integrity does not recommend proceeding with study as per email dated April 2, 2020.Risk Owner updated from A.S on August 1,	Could also impact employee safety with same H&S RR	MP-05: Integrity	2021-06-28
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										New 2019	EGI	FINAL	291	Compression Couplings Strap Failure - Isolation Concern	Tara Kuuskman	Strap(s) failure across CC isolating section of pipe from CP contributing to corrosion degradation over time possibly developing a leak	Degradation	Two different metals contacting, corrosion, degradation, stray current	Corrosion leak on pipe body and release above grade leading to flammable dispersion resulting in potential fire OR Corrosion leak on pipe body. Leak may migrate to nearby building or utility and potentially build up to LEL indoors resulting in potential explosion	1. CP inspections 2. Leak surveys 3. Gas is odourized for leak detection	Prevent Detect Detect	Public safety	Health & Safety	1	5						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2021-06-11
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate										188	LUG	FINAL	294	Hydrostatic testing procedure	Todd Piercey	Improper hydrostatic testing process. Could potentially yield the pipe or not meet required regulatory documentation.	Operator errors	Improper hydrostatic testing process.	Could potentially yield the pipe or not meet required regulatory documentation.	CMP, C&M manual, POW's	Prevent, Detect	Operational regulation	Operational	3	5							One RR only	MP-01: Asset	2021-06-29
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate										177	LUG	FINAL	295	Aldyl A PE pipe degradation	Tara Kuuskman	Leak due to degraded Aldyl A pipe	Degradation	Degraded Aldyl A pipe	Leaks and release of gas	Leak surveys	Detect	Operational reliability	Financial	1	2						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2021-06-25
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution											195	LUG	FINAL	299	Incorrect pipe specifications installed	Tracey Teed Martin	Suppliers send substitute materials (ex different pipe grade than what was specified, seamless or ERW)	Material defect	Suppliers send substitute materials (ex different pipe grade than what was specified, seamless or ERW)	Potential rework and premature asset failure	On site review (does not always happen)	Detect, Prevent	Operational reliability	Financial	3	2						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution											196	LUG	FINAL	300	Self directed contractor work quality	Tracey Teed Martin	Self-directed Alliance contractor work quality	Material defect	Quality issue with self-directed Alliance contractor	Potential rework and premature asset failure	AP have their own quality program, QA program	Detect, Prevent	Operational reliability	Financial	5	2						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
1. Natural gas distribution	1.1. Pipe		1. Ontario Distribution											197	LUG	FINAL	301	Homemade steel risers	Tara Kuuskman	Homemade steel risers used in place of prefabricated risers	Construction defect	Homemade steel risers	Potential damage to reputation	C&M Manual Integrity Manual	Prevent	Public safety	Reputational	5	2						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-01: Asset	2021-06-28
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution											200	LUG	FINAL	302	Valve operability	Tracey Teed Martin	Valve operability & functionality	Equipment malfunction	Less than 5% of the valves which were inspected failed due to being hard to turn or the valve box being damaged. About half of those failures can be attributed to the valve box.	Potential delay in isolation during emergency	C&M Manual Integrity Manual	Prevent	Public safety	Operational	3	3						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-05: Integrity	6/20/2022
1. Natural gas distribution	1.1. Pipe	1.1.1. Distribution Main	1. Ontario Distribution	1.2. Southwest (Windsor/Chatham, Sarnia/London)	1.2.5. Southwest Aggregate									201	LUG	FINAL	303	Internal Heavier Hydrocarbon Contamination in PE Pipe	Mohamed Chebaro	Hydrocarbon contamination of unknown source, permeates through the pipe wall and boils/causes bubbling in PE during heat application when a fusion is completed. Hydrocarbon contamination comes from the internal gas stream which was confirmed with PE pipe samples showing a higher concentration of contamination closer to the pipe's inner wall versus its outer wall. Financial risk driver is associated with the incremental cost of using mechanical fittings to join contaminated pipe instead of the preferred fusion method.	Degradation	Hydrocarbon contamination in natural gas (HC in C6-C15 range). The source of contaminated natural gas is currently unknown. **NOTE on Hazards / Potential Hazards** Material Degradation - Plastic Degradation	1. Leak repair with mechanical fitting can cost upwards of $300 per coupling plus associated installation costs. This financial risk is applicable to new installs off of contaminated PE pipe not just leak repairs on damaged, contaminated PE pipe. Not all costs are currently tracked however there is currently a budget of $100k in the Windsor area for PE mains and services. Consequence is considered the incremental financial impact of installing mechanical fittings. Incremental cost factors include larger excavation, multiple fittings required, larger workforce, additional inspectors, and other associated costs. 2. If bubbling is not detected during fusion, there is concern that a future leak may develop over the long term if the source of the contamination is not eliminated. Potential for leak to create public H&S impact if leak migrates to an occupied building and ignition occurs resulting in possible fatality. 3. Leak repairs on mains may result in customer loss while installing mechanical fittings.	1.1 No controls currently identified to mitigate incremental repair costs associated with installing mechanical fittings. 2.1. Procedure to detect PE bubbling and use mechanical fittings instead of PE fusion (LUG control - communication bulletin sent out to distribution operations). There is currently no way for Utility Services to detect bubbling. Only AECON can detect bubbling issue so field assumption is to use mechanical fittings as default joining method if work not completed by AECON. PE fusion is considered as the preferred pipe joining method if no bubbling. 2.2. Some PE sampling was completed, mainly in Windsor-London corridor, to conduct testing to detect extent of areas impacted by hydrocarbon contamination. 3.1. Network may be back fed to prevent customer loss.	1.1. N/A 2.1. Detect, Mitigate, & Avoid 2.2. Detect 3.1. Mitigate	Operational reliability	Financial	7	3			1. Multi-disciplinary team composed of Integrity, Engineering, Engineer Serv., Operations to evaluate contamination issue 2. Perform necessary testing on pipe samples and fusions 3. Continue to collect and analyze gas samples to determine composition of gas in system 4. Perform testing using varying compositions of hydrocarbons to identify constituents that create microbubbles 5. Leverage GTI research and recommendations to improve treatment plan 6. Leverage analysis to inform potential changes to internal standards/variance from TSSA for field practices	Fred Butrico	Ongoing	treatment plan and name update 05/01/2023 Q4 Updates: -Phase 3 gas sampling complete. Results expected in 2023. -Plastic pipe sampling deferred to 2023 to accommodate Operational resource constraints	Additional lower risk ranking for Consequence 2 and 3; Public H&S RR Low, L1, C5 Operational RR Low, L1, C3	MP-05: Integrity	2023-01-31
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution											205	LUG	FINAL	306	Cracked cap explosion	Tracey Teed Martin	Cracked cap leading to explosion	Material defect	Cap prematurely fails due to installation issue and / or material detect **Note on hazard** Could also due to Material Defect	Potential premature asset failure and rare event of fire / explosion	CMP, QA program, C&M manual, POW's, inspection, CAP	Detect, Prevent	Operational reliability	Health & Safety	1	6						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-05: Integrity	6/20/2022
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution											206	LUG	FINAL	307	Cracked cap repair	Tracey Teed Martin	Cracked cap leading to repair costs	Material defect	Cap prematurely fails due to installation issue and / or material detect	Potential premature asset failure and repair cost	CMP, QA program, C&M manual, POW's, inspection, CAP	Detect, Prevent	Operational reliability	Financial	7	1						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-05: Integrity	6/20/2022
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution											208	LUG	FINAL	309	Below grade threaded fittings	Steve McGivery	Below grade threaded fittings that cannot be repaired or tightened leading to repair costs.	Material defect	Below grade threaded fittings that cannot be repaired or tightened	Increase repair cost	Leak Survey, C&M Procedures	Detect, Prevent	Operational reliability	Financial	5	2							One RR only	MP-05: Integrity	7/4/2022
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution											209	LUG	FINAL	310	Kerotest valve bolt failure	Todd Piercey	Kerotest valve bolt failure	Material defect	Kerotest valve bolt failure	Potential H&S incident	Procedures for working safely	Prevent	Operational reliability	Operational	5	4							One RR only	MP-05: Integrity	2021-06-29
1. Natural gas distribution	1.1. Pipe		1. Ontario Distribution											211	LUG	FINAL	312	Induced steady state AC voltage	Carrie Cook	Induced steady state AC voltage above 15V on our pipelines from Windfarms or Solar Farms (feeder, gathering lines, and transmission) leading to an employee shock or personal injury OR AC Corrosion and a subsequent leak.	Accidental exposure to electrical voltage	Induced voltage due to adjacent electrical facilities or weather conditions	injury to an employee in contact with energized system	Crossing Agreement, separation from pipeline. CSA 22.3 No 6, UG standard for work boots and gloves, C&M 5.8 listing for Induced AC lines. All lines found to have >15VAC are mitigated upon discovery.	Prevent	Workforce safety	Health & Safety	1	2							One RR only	MP-04: Health & Safety	2021-06-25
1. Natural gas distribution	1.1. Pipe		1. Ontario Distribution											212	LUG	FINAL	313	Transient AC voltage	Tracey Teed Martin	Induced Transient AC voltage (fault condition) onto our pipelines from Wind farm lines leading to an employee shock or personal injury or damage to Union Gas facilities.	Accidental exposure to electrical voltage	Induced voltage due to adjacent electrical facilities or weather conditions	injury to an employee in contact with energized system	Crossing Agreement, separation from pipeline. CSA 22.3 No 6, UG standard for Work boots and gloves , C&M 5.8 listing for Induced AC lines, Ontario One Call, UG Policy on working in inclement weather (lightening). Fault arrestors on Hydro system.	prevent	Workforce safety	Health & Safety	1	5						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-04: Health & Safety	6/20/2022
1. Natural gas distribution	1.1. Pipe		1. Ontario Distribution											213	LUG	FINAL	314	Pipe washout	Ryan Werenich	Pipe subjected to washouts	Natural forces/weather	pipe washout and undermining caused by flooding and erosion or sinkhole	pipe could be damaged and extensive repair required	C&M, ERP	Prevent Mitigate	Operational reliability	Financial	5	4						Risk Owner Updated from A.S. August 1, 2023	One RR only	MP-05: Integrity	2023-08-01
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution											214	LUG	FINAL	315	Flooding in DO	Steve McGivery	Pipe subjected to floods	Natural forces/weather	Flooding	Potential operation and financial impacts	ERP	Mitigate	Operational reliability	Financial	1	3							Operational: Low L1 C2	MP-05: Integrity	7/4/2022
1. Natural gas distribution	1.1. Pipe		1. Ontario Distribution											43	LGD	FINAL	316	Erosion due to flooding	Ryan Werenich	Erosion may occur naturally from flooding (see flooding) or induced soil erosion from water main breakage, resulting in loss of supporting soil for pipe and fracture / loss of containment	Natural forces/weather	Erosion (e.g. due to flooding or induced soil erosion from water main breakage) in near vicinity which could impact the integrity of gas carrying assets	Potential loss of containment leading to uncontrolled release of natural gas	27. Scheduled Air Patrol Survey - Vital Mains (CER, IMP, UTP) in EGD and Public ROW 278. Ground cover monitoring programs 103. Construction and Maintenance Manuals 93. Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan) 267. MP Manuals 268. EM (Emergency Management) exercises 269. Contingency plans 270. Business Continuity Management (BCM) Program	Detect Prevent Prevent Mitigate Detect Mitigate Mitigate Mitigate Mitigate	Operational reliability	Operational	5	4						Risk Owner Updated from A.S. August 1, 2023	Financial: Low L1 C3 Operational: Low L1 C2, Low L5 C1 (Erosion due to flooding)	MP-05: Integrity	2023-08-01
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution											215	LUG	FINAL	318	Wild fire or forest fire	Tara Kuuskman	Wild fires in designated forest fire zone leading to pipeline damage	Natural forces/weather	Wild fire	Pipeline damage	ERP	Mitigate	Operational reliability	Financial	5	3						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-02: Emergency	2021-06-11
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation											3	LGD	FINAL	321	Non-cultivated vegetation in vicinity of STO gas-carrying assets	Wes Armstrong	Non-cultivated vegetation could lead to potential non-compliance issues, impact operation, impair integrity of assets, increase fire hazard and create security issues	Weather and Outside Forces	Non-cultivated vegetation growth around gas carrying assets due to various reasons such as: - Incompatible vegetation growth by landowner and cities - Potential not following company procedure for easement cleaning - Lack of maintenance (e.g. due to restriction in resources) **NOTE on hazards / potential hazards : Also applicable hazards are:** Dropped or falling objects (e.g. dead vegetation falls on a station) Incorrect operation (e.g. not following company procedure and lack of maintenance)	Potential non-compliance issues, impact operation, impair integrity of assets, increase fire hazard and create security issues **NOTE:** Operational impact is based on impair access and survey work, leading to delay or inability to detect leaks in timely manner, delay emergency responses (Diversion of Enbridge resources)	- Easement agreement - Landowner outreach - C&M 37 : Vegetation management - STO SOP which mentions easement clearance - Brushing and easement clearance operating std - Emergency Processes in various manuals - C&M, EH&S, CER and ERP (Emergency Response Plan)	Prevent Prevent Prevent Prevent Prevent Mitigate	Operational reliability	Operational	6	3							Reputational - Lead to non-compliance issue : L6C2 Medium Health & Safety - Increase fire hazards. (natural forces have been covered by other risks. This is to address man-made fire) : L2C2 Low Financial - Potential extra stress on piping system (including pipes and stations) impacting integrity of assets, e.g. tree roots grow around pipeline, dent or deform the pipeline. If trees over the pipeline get taller, they are more prone to lightning strikes which can conduct down the tree and onto the pipeline creating leaks, coating damage, cathodic protection damage and tracer-wire damage (for plastic pipe). : L3C3 Low	MP-01: Asset	2021-06-23

First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version	Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard	Source	Consequences	Controls	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										3	LGD	FINAL	322	Non-cultivated vegetation in vicinity of DO gas-carrying assets	Steve McGivery	Non-cultivated vegetation could lead to potential non-compliance issues, impact operation, impair integrity of assets, increase fire hazard and create security issues	Weather and Outside Forces	Non-cultivated vegetation growth around gas carrying assets due to various reasons such as: - Incompatible vegetation growth by landowner and cities - Potential not following company procedure for easement clearing - Lack of maintenance (e.g. due to restriction in resources) **NOTE on hazards / potential hazards : Also applicable hazards are:** Dropped or falling objects (e.g. dead vegetation falls on a station) Incorrect operation (e.g. not following company procedure and lack of maintenance)	Potential non-compliance issues, impact operation, impair integrity of assets, increase fire hazard and create security issues **NOTE:** Operational impact is based on impair access and survey work, leading to delay or inability to detect leaks in timely manner, delay emergency responses (Diversion of Enbridge resources)	- Easement agreement - Landowner outreach - C&M 37 : Vegetation management - Brushing and easement clearance operating std - Emergency Processes in various manuals - C&M, EH&S, CER and ERP (Emergency Response Plan)	Prevent Prevent Prevent Prevent Mitigate	Operational reliability	Operational	6	3							Reputational - Lead to non-compliance issue : L6C2 Medium Health & Safety - Increase fire hazards. (natural forces have been covered by other risks. This is to address man-made fire) : L2C2 Low Financial - Potential damages to stations such as dead vegetation falls on a station (e.g. dead trees) : L3C2 Low	MP-01: Asset	7/4/2022
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											New 2019	LGD	FINAL	330	K-701, 702, & 703 Reliability of Compression Units at Corunna	Wes Armstrong	Aging compression units (K-701/2/3) at Corunna Compressor Station are prone to failure and diminishing OEM support. This would increase maintenance cost and incur gas supply cost in case of failure.	Degradation	Various compressor degradation over operating life of compressors. Failure frequency of K701/2/3 is higher than other units but they are also operated as last-on units. OEM support is diminishing but not certain if/when it will be completely non-existent. Likelihood rating is based on EGD failure data.	Increased failures, maintenance costs, and downtime resulting in buying more expensive gas on the market to meet demand. If OEM support is no longer available, obtaining replacement parts will become cost prohibitive. If parts can't be procured and units are out for an extended period of time, operational capability will be significantly impacted. Consequence rating is based on estimation of increasing maintenance cost and gas supply cost.	Maintenance Program	Prevent	Operational reliability	Financial	5	5			Economic assessment completed for alternative options. Options such as compressors replacement (gas and electric driven), installing a high-pressure transmission line between Dawn and SCOR are being considered for the integrated storage system (Dawn to Corunna project). -20 km NPS 36 (TR7) pipeline approved by Capital Allocation Committee (CAC). LTC application approved by OEB November 3, 2022 for ISD of 2023. -A comprehensive to review the reliability, availability and maintainability (RAM) risks at the site through a RAM study was completed in 2022, with support from external consultant that provided an understanding of site wide operational risks	Paul Norris	2023	After Q1, 2022, risk ranking changed from medium to high. The likelihood remained at a 5 while the consequence was changed from 4 to 5. -treatment plan update 10/13/2022 Updated treatment plan and treatment owner (1/31/2023)	One RR only	MP-01: Asset	2023-01-31
2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											New 2019	LGD	FINAL	331	Loss of Deliverability due to Well Abandonments	Wes Armstrong	Wells have been abandoned due to micro-annulus leaks at Kimball reservoirs and Dow Moore reservoir leading to loss of deliverability/injectability. The result is an incremental increase in gas supply costs.	Degradation	Degradation over operating life of asset	Micro-annulus leaks at Kimball and Dow Moore reservoirs leading to loss of deliverability/injectability resulting in increased gas supply costs	Operations Planning to make up for lost deliverability Alternate gas supply planning	Prevent Mitigate	Operational reliability	Financial	4	3			1) Continue to assess the deliverability of the Storage Wells	Steve Pardy	2022	Proposed timeline changed to 2022 - 06/22/2022 -treatment plan updated 10/13/2022, Justification of Re-evaluated ranking: Several wells have been drilled ever since the abandonment of the wells. Enbridge has been living with any financial consequences and there have not been substantial incremental costs (costs are not necessarily explicit as they are blended with other costs) - 1/31/2023	One RR only	MP-01: Asset	2023-01-31
2. Pipeline transportation of natural gas	2.4. Storage	2.4.1. Pool	2. Ontario Transportation											233	LUG	FINAL	334	Water Well Contamination	Steve Pardy	The surrounding water wells are contaminated due to drilling/operation of the well using a rotary rig.	Reservoir integrity	damage to landowner water well due to company drilling activity	potential public safety consequence, company reputational damage	Fresh water zone will be isolated with casing and cement prior to proceeding with the rest of the hole. The Environmental consultant will develop a water wells monitoring program. Only operating up to 80 percent of fracture gradient	prevent	Environmental	Reputational	3	3							Reputational: Low L1 C3	MP-03: Environmental	2021-06-21
1. Natural gas distribution	2.1. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate										263	LUG	FINAL	336	As-Built Station Records	Tracey Teed Martin	There is an identified gap in accurate and reliable station as built records (piping, fittings, valves, electrical, equipment) that are complete and accessible. This may result in regulatory fines for not having proper records of our facilities, operational and personal safety issues resulting from a reduced ability to respond effectively to emergencies. Additional costs associated with completing engineering designs are frequently a result of missing or inaccurate station records.	Missing, incorrect or incomplete records	Incomplete records	Possible compliance issue	Planning Design & Records Manual	Mitigate	Operational regulation	Reputational	7	2						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
1. Natural gas distribution	2.1. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									264	LUG	FINAL	337	Pressure Vessel Integrity Program	Tara Kuuskman	Lack of pressure vessel integrity program. Union Gas does not currently have a formal pressure vessel integrity program. Pressure vessel integrity is a Z662 requirement.	Incorrect operation	Inadvertent operation - field changes to station		There is an all-encompassing pressure vessel integrity program currently being fully implemented.	Prevent / Detect	Operational regulation	Reputational	1	5						Risk Owner updated from A.S on August 1, 2023	One RR only	MP-05: Integrity	2022-06-14
3. Aggregate			3. Aggregate											265	LUG	FINAL	338	Material and Purchase Order Records	Tracey Teed Martin	There has been an identified challenge to keeping material and purchase specs up to date. Union Gas is out of compliance on many of these specs. This could lead to delays and overruns in projects.	Missing, incorrect or incomplete records	Inadvertent out of date material and purchase specs	Possible non-compliance issues may lead to project delays and overruns resulting in financial impacts	Planning Design & Records Manual	Prevent	Operational regulation	Financial	5	4						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											266	LUG	FINAL	339	GPI for Compressor Station Mechanics	Tracey Teed Martin	Compressor station mechanics do not have GPI (need for line locating, inspection, third party, replacement of fittings/pressure testing)	Incorrect operation	Compressor station mechanics do not have GPI (need for line locating, inspection, third party, replacement of fittings/pressure testing)	Possible non-compliance issue resulting in reputation impact	SOP	Prevent	Operational regulation	Reputational	6	3						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											267	LUG	FINAL	340	IMT Designation	Tracey Teed Martin	IMT (Industrial Maintenance Technician) designation (all Hagar employees have but none at any other location)	Incorrect operation	Competence issues with employee	Possible non-compliance issue resulting in reputation impact	Operator Training and Qualification	Prevent, Mitigate	Operational regulation	Reputational	3	3						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.3. Pipeline Aggregate	2. Ontario Transportation											268	LUG	FINAL	341	Transmission MOP Records (including 30% SMYS)	Tracey Teed Martin	Pipelines potentially operating above their true/verified MOPs due to lack of cohesive reviews of MOPs	Pipelines potentially operating above their true/verified MOPs	Lack of cohesive reviews of MOPs which include records, identification of materials and pressure ratings, identification of SMYS	An overpressure operating condition leading to a noncompliance.	1. Within LEGD all 30% SMYS assets have been verified with respect to MOP and for almost all XHP pipelines 2. TRIM program at LUG has records available 3. A multi year plan is available to inspect all TIMP pipelines to detect anomalies and appropriate repairs	Prevent	Operational regulation	Reputational	6	3			Investigate establishing MOP Verification program with dedicated resources specifically for LUG TIMP pipelines	Todd Piercey	2029 (To be updated as applicable)	Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022 The risk assessment has also identified an impact of failure of the pipeline, which is not included in the integrity program (transmission), leading to leak or rupture.	H&S (Public): L1C6 Fin: L3C5	MP-01: Asset	10/24/2022
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate										269	LUG	FINAL	342	Distribution MOP Records	Tracey Teed Martin	Pipelines potentially operating above their true/ verified MOPs due to lack of cohesive reviews of MOPs	Pipelines potentially operating above their true/ verified MOPs	Lack of cohesive reviews of MOPs which include records, identification of materials and pressure ratings, identification of SMYS	An overpressure operating condition leading to a noncompliance.	1. TRIM program at LUG has records available	Prevent	Operational regulation	Reputational	6	3						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022 The risk assessment has also identified an impact of failure of the pipeline, which is not included in the integrity program (distribution), leading to leak or rupture.	H&S (Public): L2C5 Fin: L3C4	MP-01: Asset	10/24/2022
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate										271	LUG	FINAL	344	GIS Records (Station & Facility)	Murray Costello	Lack of historical records to validate location of facilities in GIS. Could potentially lead to 3rd party damage. Stations that physically exist in the world but are not in GIS. Including system valves (i.e. inlet and outlet valves)	Missing, incorrect or incomplete records	Lack of historical records to validate location of facilities in GIS. Could potentially lead to 3rd party damage. Stations that physically exist in the world but are not in GIS. Including system valves (i.e. inlet and outlet valves)	Potential compliance issue and increase likelihood of 3rd party damages	Management of Change Policy	Prevent	Operational regulation	Health & Safety	5	3			Currently locating stations 30% SMYS and above right now with no plans of doing the others. LEG will be finished in 2022 with all the stations that we can access visited and the records and systems updated as needed. If we are unable to get into the station we will pass these over to the Network Ops group to have done when they are inspecting the station. (20210614 Lori Waite)	Andrew Welburn	2022	Treatment plan complete - 5/2/2023	Reputational: Medium L6 C3	MP-01: Asset	2023-05-02
2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.3. Pipeline Aggregate	2. Ontario Transportation											272	LUG	FINAL	345	Mapping Records	Andrew Welburn	Inaccurate mapping records. Affects ability to respond to emergencies, perform locates and complete all SOP work. This includes storage gathering and transmission lines.	Missing, incorrect or incomplete records	Incomplete records	Possible operational disruption and compliance issue	Planning Design & Records Manual Gas Storage Manual	Prevent	Operational regulation	Operational	5	3						Risk Owner Updated from Shawn K to Andrew W 6/13/2023	One RR only	MP-01: Asset	2023-06-13
1. Natural gas distribution	2.6. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution											273	LUG	FINAL	346	New equipment, materials, and tools	Tracey Teed Martin	Lack of process and procedures for introducing new equipment, materials and tools	Design error	Inadvertent operation	Possible worker injury	Management of Change Policy	Prevent	Workforce safety	Health & Safety	5	4						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
1. Natural gas distribution	2.1. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate										274	LUG	FINAL	347	Station MOC	Murray Costello	Changes to station without Engineering knowledge, unapproved installations, infringement of hazardous areas, improper applications of equipment and controls. Rebuilds or repairs required.	Design error	Inadvertent operation - field changes to station	Possible financial cost to rebuild or remediate certain unapproved changes	Management of Change Policy	Prevent	Operational reliability	Financial	5	3							One RR only	MP-01: Asset	2021-06-23
1. Natural gas distribution														275	LUG	FINAL	348	SMC Process, Procedures, and Training	Murray Costello	SMC is forgotten for roll-outs (process, procedures, programs) and training	Incorrect operation	stations group not provided necessary training and updates on procedures	this could result in incorrect operation and subsequent operational, H&S or non-compliance issue	ABC Effective readiness	Prevent	Operational reliability	Reputational	3	2							One RR only	MP-01: Asset	2021-06-23
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation											276	LUG	FINAL	349	Commissioning and maintaining heating systems at stations	Amanda Murray	G1/G2 - lack of ticket holders to complete commissioning/maintenance on heating systems (Ontario Regulation 215/01)	Missing, incorrect or incomplete records	G1/G2 - lack of ticket holders to complete commissioning/maintenance on heating systems (Ontario Regulation 215/01)	Potential compliance issue	UG trains technicians on heating systems: interpreted to be adequate for IMT (industrial maintenance technician) certificate	Prevent	Operational regulation	Reputational	3	4						Risk Owner Updated from Dean D to Amanda M April 28, 2023 (AMH)	One RR only	MP-01: Asset	2021-06-23
1. Natural gas distribution	1.1. Pipe	1.1.4. Pipe Aggregate	1. Ontario Distribution											277	LUG	FINAL	350	EOP to MOP pressure increase	Tracey Teed Martin	Significant increase in pressure from EOP (Established Operating Pressure) to MOP.	Operate beyond allowable limits	Pressure increase	Possible overpressure resulting in possible fatality	C&M Manual	Prevent	Public safety	Health & Safety	1	6							One RR only	MP-01: Asset	2021-06-28
2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.3. Pipeline Aggregate	2. Ontario Transportation											279	LUG	FINAL	352	Design Philosophy for Piggable Lines	Tracey Teed Martin	Design philosophy on making lines piggable or tool selection process may compromise data collection.	Design error	Unpiggable pipelines due to design or inadvertent selection of incorrect pig tool	Compromised data collection from pig run resulting in possible operations disruptions	C&M Manual Internal design review process TIMP	Prevent Prevent Detect, Prevent	Operational regulation	Operational	7	2						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-05: Integrity	6/20/2022
1. Natural gas distribution	1.1. Pipe	1.1.4. Pipe Aggregate	1. Ontario Distribution											280	LUG	FINAL	353	Designer Accountability	Todd Piercey	Competence of design personnel designing pipeline to incorrect class location	Incorrect operation	Inadvertent out of date material and purchase specs	Potential for re-work or redesign	Planning Design & Records Manual C&M Manual	Prevent	Operational reliability	Financial	3	2							One RR only	MP-01: Asset	2021-06-28
2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation											281	LUG	FINAL	354	Lack of as Built Drawings of Wellheads	Steve Pardy	Lack of as built drawings of wellheads related to legacy EGD wells. Lack of records in wellview. As built information is not always sent in from the field.	Missing, incorrect or incomplete records	Incomplete records	Possible operational disruption and compliance issue	Planning Design & Records Manual Gas Storage Manual	Prevent	Operational regulation	Reputational	4	3			As-built drawings are currently being generated for the well where work is undergoing	Mike Learn	2025	Likelihood & consequence ranking change - "Justification: Previous request from TSSA requesting encroachment records. Possibility of Ministry of Natural resources requesting the same".	One RR only	MP-01: Asset	2022-06-07
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution											283	LUG	FINAL	356	SAP PM Station Records	Andrew Welburn	Missing or incorrect information in SAP PM. In some instances stations physically exist in the world, but are not in SAP PM at all.	Missing, incorrect or incomplete records	Incomplete records in SAP PM for stations	Potential inadequate / incorrect / missing maintenance activities at stations, leading to compliance issue and potential damage to company's reputation	C&M Manual Planning Design & Records Manual	Prevent	Operational regulation	Reputational	7	2			There is currently a plan to add a number of resources in Records team to support adding missing stations into SAP PM. This is part of the 2022 Budget in IAM	Andrew Welburn	2023	Risk Owner Updated from Shawn K to Andrew W 6/13/2023	One RR only	MP-01: Asset	2023-06-13
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.2. Southwest (Windsor/Chatham, Sarnia/London)										284	LUG	FINAL	357	Service Records in Union South	TBD	Lost, damaged, missing or inadvertently disposed source records and data. This includes "scanned services" in Union South.	Missing, incorrect or incomplete records	Incomplete records	Possible operational disruption and compliance issue	Planning Design & Records Manual	Prevent	Operational regulation	Reputational	6	2							One RR only	MP-01: Asset	2023-08-01
1. Natural gas distribution	1.1. Pipe	1.3.1. Gas Service	1. Ontario Distribution											285	LUG	FINAL	358	Service GIS Records in Legacy Centra	TBD	There are number of services in the former Centra Franchise where the service is not necessarily mapped completely in the GIS. This could potentially lead to a third party damage risk.	Missing, incorrect or incomplete records	damage to company buried facilities due to lack of complete records impairing ability to provide accurate locate caused by integration with Centra Gas and challenges with records integration	damage to facilities resulting in damage to company facilities and reputational damage	There is a notional indicator in the GIS and a link to a scan of the original service record.	Prevent	Operational regulation	Reputational	1	5							One RR only	MP-01: Asset	2023-08-01
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate										286	LUG	FINAL	359	Out of Date Technical Documentation	Tracey Teed Martin	Documentation Currency. Some of Union Gas technical documentation are out of date or in conflict with other technical documentation.	Incorrect Operation	operational incident caused by reference to out of date technical document (i.e. standard, procedure)	could result in non-compliance, operational upset causing customer impact and/or regulatory concern	Defined intervals in Content Management standards for the review period for high risk manuals. There is reporting on the status of each of the high risk manuals. A search can now be done and list all of out of date section of manuals grouped by owner. If a person cannot update their section of a manual within 7 years, they would require director approval.	Prevent	Operational reliability	Reputational	5	3						Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022	One RR only	MP-01: Asset	6/20/2022
2. Pipeline transportation of natural gas	2.4. Storage	2.4.3. Storage Aggregate	2. Ontario Transportation											290	LUG	FINAL	363	STO Training Program	Wes Armstrong	Lack of complete and documented technical training curriculum at STO - When factoring in upcoming retirements and expansion, there are not sufficient training programs at STO to meet the requirements. The current curriculum training program is covering all STO facilities and is comprehensive, consistent and documented but still has many years to capture all of the content at the current resource levels.	Incorrect operation	Lack of technical training for frontline operations personnel	lack of training could result in process, safety issue, injury, equipment damage, operational impacts	Emergency Response Program, Job mentoring, processes and procedures. There is a variety of training, but much is left up to the individual manager. A lot is also expected from mentoring or shoulder to shoulder training. Given the amount of upcoming retirements and expansion, this could potentially lead to safety, financial or reliability consequences.	Mitigate Prevent	Workforce safety	Health & Safety	5	4			The on-going project to complete the STO technical training program (Curriculum) needs to continue or accelerate to meet the upcoming requirements based on expected needs.	Kevin Pomeroy	2023	Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023	One RR only	MP-01: Asset	2023-02-28
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution											37	LGD	FINAL	366	Wild Fire	Steve McGivery	Ground cover ignites around gas carrying assets due to wild fire	Natural forces/weather	Wild fire	Potential impact isolated area, leading to inability to isolate gas carry assets, could potential damage gas carry assets	120. Warning systems 43. Vegetation Management 267. MP Manuals 268. EM (Emergency Management) exercises 269. Contingency plans 270. Business Continuity Management (BCM) Program	Detect Mitigate Detect Mitigate Mitigate Mitigate Mitigate	Operational reliability	Operational	5	3							One RR only	MP-02: Emergency	7/4/2022
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.6. Eastern (Area 60, Legacy EGD & Gazifère)	1.6.2. 90 - Gazifère									46	LGD	FINAL	397	Recall of rental equipment	Jean-Benoit Trahan	Potential recall or safety concern for multiple customer's where rental equipment (30,000 in Gazifère)	Manufacturing defects	Recall or safety concern with rental equipment	Potentially affect multiple customers	- Monitoring or recalls - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan) - MP Manuals	Prevent Mitigate Detect Mitigate	Operational reliability	Operational	2	5							One RR only	MP-02: Emergency	2021-06-23
2. Pipeline transportation of natural gas	2.4. Storage	2.4.5. Transportation Aggregate	2. Ontario Transportation											47	LGD	FINAL	398	Gas Supply Shortage from TCPL or Gas Storage	Clancy O'Hara	TCPL or Gas Storage issues could create a shortage of upstream gas supply. Severely cold weather could create a restriction in capacity to end users.	Loss of upstream feed	Issues with TCPL or Gas Storage	Shortage of upstream gas supply. Severely cold weather could create a restriction in capacity to end users	- Gas curtailment procedures as outlined in the EPM - Redundant feeds and use of alternative feed mechanisms such as LNG - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan) - EM (Emergency Management) exercises - Contingency plans - Business Continuity Management (BCM) Program	Mitigate Mitigate Mitigate Mitigate Mitigate Mitigate	Operational reliability	Operational	5	4							One RR only	MP-02: Emergency	2021-06-11
3. Aggregate			1. Ontario Distribution	1.14. EGI Aggregate										48	LGD	FINAL	399	Disease outbreak	Wes Armstrong	Communicable disease outbreak more serious that seasonal influenza that impacts 25% or more of the workforce	Exposure to contagious, infections, or pandemic diseases	Pandemic and/or communicable disease	Communicable disease outbreak more serious that seasonal influenza	- Enterprise Public Health Emergency Plan - Annual flu program - EHS communication - PPE - Site specific hazard form - EM (Emergency Management) exercises - Business Continuity Management (BCM) Program	Prevent Prevent Prevent Prevent Prevent Mitigate Mitigate	Operational reliability	Operational	5	4							H&S:	MP-04: Health & Safety	2022-07-20
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate									49	LGD	FINAL	400	[redacted]	Steve McGivery	[redacted]					Mitigate Mitigate	Operational reliability	Operational	2	5						[redacted]	One RR only	MP-02: Emergency	7/4/2022
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate									50	LGD	FINAL	401	Employee Injury during Emergency Response	Steve McGivery	Employee injury in response to an emergency	Response to hazardous situations (e.g. emergencies)	Employee(s) injuries during response	Employee(s) could be exposed to hazardous situations while responding to an emergency	- Site specific hazard form - PPE - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan) - EH&S Procedures - MP Manuals	Prevent Mitigate Mitigate Mitigate Mitigate	Workforce safety	Health & Safety	5	2							One RR only	MP-02: Emergency	7/4/2022
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										51	LGD	FINAL	402	[redacted]	Clancy O'Hara	[redacted]					Detect Mitigate Mitigate Mitigate	Operational reliability	Operational	1	6							One RR only	MP-08: Control Room	2021-06-11
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate									111	LGD	FINAL	404	[redacted]	Clancy O'Hara	[redacted]					Prevent Prevent Prevent Detect Detect Mitigate Mitigate Mitigate Mitigate Mitigate	Operational reliability	Operational	4	5							H&S: Medium L1 C6	MP-06: Security	2022-11-01
1. Natural gas distribution	1.2. Station	1.2.1. Customer Station	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate									Updated 2020	EGI	FINAL	405	Legacy Inside Regulators at Sales, Header, or Customer Stations typically applies to Condo buildings in urban areas	Tracey Teed Martin	Leaks from higher operating pressure piping will have a larger leak rate than pipes operating at lower pressures (for same hole size). Indoor regulators cause higher operating pressure pipe indoors - potential leaks may be able to reach LFL faster	3rd party damage	1. Third party "pull" damage may cause the service to leak or fully separate at the indoor regulator inlet connection (there is a chance the pull damage leak may occur outside the customer premise) 2. Failure of pressure control equipment leading to potential overpressure of downstream appliances and indoor leak from appliance. 3. Corrosion hazards to services may cause leak from service that could potentially migrate indoors. **NOTE on Hazards** 3rd Party Damage could be due to Latent Damage, Mechanical Damage (Collision, Excavation, HDD, Vandalism) Other hazards are: 1st & 2nd Party Damages due to Mechanical Damage (Excavation, HDD), Equipment Failure due to Malfunction of Control/Relief and External Corrosion due to Atmospheric Corrosion and External Metal Loss	Depending on leak rate, building ventilation, and room size, it is possible for indoor gas leak to build up to LFL leading to possible ignition resulting in an explosion with the potential to result in > 10 public fatalities	'-Locate procedures & call before you dig. Some locations also have a warning sign for "below grade service entry" to raise public awareness to get locates before excavation. -Some locations have an excess flow valve (EFV) on service or "weak link" (transition to PE, above grade shut off valve before building entry, etc.). -Gas is odourized for leak detection -Building ventilation limits gas build-up (as per minimum building codes) -Emergency call procedures i.e. customer advised to open windows or evacuate immediately etc. depending on situation -Emergency response procedures -Leak survey may detect latent damages that eventually develop into a leak some time after initial line strike	Detect & Prevent Prevent Detect, & Mitigate Mitigate Prevent Prevent Detect	Public safety	Health & Safety	2	7			1. Consider relocating indoor regulators into an external regulator room (ERR) or relocate outdoors if possible, to do so. Some locations may not be immediately possible to relocate due to external factors not under the company's control, however over the long-term relocation may be possible. Similar treatment plans were previously considered and initiated in both legacy parts of the business. 2. Consider retrofitting services without an excess flow valve (EFV) to include one. Alternatively if an EFV cannot be designed to function as intended for a service with an inside regulator, consider adding a "weak link" to service such as transition to PE and/or above grade shut off valve before building entry (alternative is not a consideration for service regulators located outside). Note that EFV are potentially limited in design due to customer demand and/or delivery pressure vs. flow set point limitations of EFVs i.e. not all service may be possible to design an EFV for.	Kirby Skinn-Jones	Ongoing	Risk owner change from Mike Wagle to Tracey Teed Martin - 06/20/2022 Treatment Owner change from Kirby Skinn-Jones to Matthew Watson 8/15/2022 Treatment Owner changed to Kirby Skinn-Jones 2/8/2023 Timeline changed from 2022 to ongoing - 5/2/2023	One RR only	MP-01: Asset	2023-05-02
1. Natural gas distribution	1.1. Pipe	1.1.3. Gas Service	1. Ontario Distribution	1.13. Legacy EGD Aggregate										New 2019	LGD	FINAL	406	Exposing potentially leaking below grade risers	Tara Kuuskman	During scheduled replacement of degraded below grade riser assets, daylighting the asset could possibly expose/create a leak leading to fire hazard	Degradation	Internal erosion-corrosion degradation over time (applicable to; amp fitting, other fitting, copper services, steel risers) Slow crack growth degradation over time (applies to; PE services - riser section with sheathing, anodeless risers - PE material)	Scheduled replacement of old asset leads to exposure of leaking riser, release to atmosphere that may ignite resulting in possible fire damage to public property / impact to public and worker safety - H&S impact, typically two workers present during excavation	1. Amp fitting replacement guidelines to visually check for ignition sources, bar hole to check for leaks, and cut back (remote isolation) available to isolate leaks 2. Gas is odourized for leak detection 3. Leak survey	Prevent Detect	Workforce safety	Health & Safety	2	5						Risk Owner updated from A.S on August 1, 2023	Financial C4, L3, RR M	MP-05: Integrity	2021-06-28
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution			132	LUG	DRAFT	165	Station overpressure compliance issue	TBD	Station piping overpressure causing code compliance issue		New 2019	EGI	FINAL	407	Overpressure of Low Pressure (LP) System	Murray Costello	Possible overpressure of LP system due to various causes of station pressure regulator malfunction open and all controls failing leading to potential downstream effects. Investigation in progress through QRA and EA.	Equipment malfunction	Debris on regulator seat Debris on pilot seat Broken regulator spring Break in mechanical linkage on pilot Frozen pilot (water into spring barrel chamber). Significant flooding of station box has not occurred in the past Leak on sense line due to damage (minor leaks not a regulator fail open concern) Car impacts station A/G vent line possible water ingress into spring case External fire impacting station melts regulator internals Blocked station vent Procedural error **Note on Hazard** Other applicable hazard is Incorrect Operation	Pressure increase leading to possible overpressure (full inlet pressure) resulting in downstream indoor leaks and possible fire or explosion	Equipment Malfunction Controls: 1. Monitor regulator or full capacity relief valve 2. Token relief alerts public to make emergency call to the Company with operator action 3. Routine operational inspection and maintenance 4. ERX pressure recorders and alarms with operation response on some stations 5. Filters on pilot regulators 6. Atmospheric sense lines vented A/G outside of the box 7. Regulator cap with gasket prevents water ingress to spring barrel chamber Procedural Error Controls: 1. Standalone procedures for each operation that could potentially impact station pressure control 2. System isolated with LOTO management policy - before work begins the station regulator run outlet and inlet station block valves would be closed. Including closure of valve downstream of sense line on main line (i.e. the station would be completely isolated). 3. Worker qualification before work OQ (Operator Qualification - EGD term) CAP (Competency Assessment Program UGL term) 4. Pressure gauges with operator monitoring	Equipment Malfunction Controls : Prevent Detect Prevent, Detect Detect Prevent Prevent Prevent Procedural Error Controls: Prevent, Detect Prevent Prevent Prevent, Detect	Public safety	Health & Safety	3	7			-Risk Services completed regional workshops in Q2 2021 to assign risk rankings to 309 individual stations -Treatment plans address High risks in each region – investments in Copperleaf -Retrofitting stations to include an additional pressure control device (either one of full capacity relief, monitor regulator or slam-shut valve) at the existing station so that minimum code requirements are met -Rebuild network to IP including stations and provide each customer in network with a service regulator (with internal relief) at the customer meter set -Rebuild station to new engineering standard for LP stations	Dayana Musa	2023	Updated treatment proposed timeline from TBD to 2023 treatment plan update 10/13/2022 Updated treatment plan 1/31/2023 Q4, 2022: Implementation of risk treatment / action plans is underway -All High-risk stations have short term plans starting in 2023 -2 stations that had no short-term plans at the time of July 14th director endorsement now have plans and have been prioritized for execution in 2023	Previously ranked as L2 C6 (medium risk) for procedural error risk and equipment malfunction. Combined and risk rank updated on 08/12/2020	MP-01: Asset	2023-01-31
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation											New 2020	EGI	FINAL	411	Siemens Valve Controller	Wes Armstrong	The Siemens valve controllers are essential components to operate the fuel system on GDS transmission compressors. The manufacturer has issued notice that they will no longer be supporting these valve controllers as of the summer of 2020. This creates an elevated risk to GDS transmission reliability		Potential failures of controller GDS has already seen a number of failures on these units in the past (8 in total at the time of the risk review in 2019). Once support from the OEM is discontinued, there will be no option for immediate repair and transmission reliability will be compromised. As of 08-2020: - It has been confirmed that the OEM has officially stopped supporting these valve controllers - In 2020, failures have occurred at Parkway C, Parkway D and Lobo D.	If failures continue and there is no available repair option, transmission reliability could be impacted and operational reliability consequences could be incurred.	Spare parts created by replacement program Contingency planning for loss of supply LCU coverage	Prevent Prevent Mitigate	Operational reliability	Operational	6	4			-Program – 2 units per year. Start in 2020, target completion in 2025. -Specific Units identified for 20 & 21 -2021 (Bright A1 & A2) -Spares inventory created as replaced. -Short-term risk treatment – A strategy to increase spare parts inventory is underway -The vendor will no longer support these valve controls	Paul Norris	2025	treatment plan update 10/13/2022 Treatment owner updated 1/31/2023 Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023 Q1 2023 Update: Parkway B – installed in 2022 Bright A1/A2 – installed in 2022 Lobo C & Parkway C – material to be delivered in May 2023, install in 2024		MP-01: Asset	2023-02-28

First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version	Current ID
3. Aggregate			3. Aggregate											2019	EGI	FINAL	412
														2019	LUG	FINAL	413
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.13. Legacy EGD Aggregate										2020	EGI	FINAL	414
3. Aggregate			3. Aggregate											2020	EGI	FINAL	416
2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.3. Pipeline Aggregate	2. Ontario Transportation	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	420
2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.3. Pipeline Aggregate	2. Ontario Transportation	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	421
2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.3. Pipeline Aggregate	2. Ontario Transportation	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	422
2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.3. Pipeline Aggregate	2. Ontario Transportation	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	423
2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.3. Pipeline Aggregate	2. Ontario Transportation	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	424
2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.3. Pipeline Aggregate	2. Ontario Transportation	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	425
1. Natural gas distribution	1.3. Customer asset	1.3.3. Customer Asset Aggregate	1. Ontario Distribution	1.12. Legacy UGL Aggregate	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	426
1. Natural gas distribution	1.3. Customer asset	1.3.3. Customer Asset Aggregate	1. Ontario Distribution	1.13. Legacy EGD Aggregate	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	427
1. Natural gas distribution	1.3. Customer asset	1.3.3. Customer Asset Aggregate	1. Ontario Distribution	1.13. Legacy EGD Aggregate	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	428
1. Natural gas distribution	1.3. Customer asset	1.3.3. Customer Asset Aggregate	1. Ontario Distribution	1.13. Legacy EGD Aggregate	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	429
1. Natural gas distribution	1.3. Customer asset	1.3.3. Customer Asset Aggregate	1. Ontario Distribution	1.13. Legacy EGD Aggregate	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	430
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate	34	LUG	DRAFT	48	Service Regulator malfunction - diaphragm	TBD	Aging (regulator diaphragms) - increases risk of an overpressure if vent gets blocked - older regulators have less resistance to vent freezing Loss of pressure control and overpressure protection due to malfunction of service regulator.	Equipment malfunction	N/A - New after merge	EGI	FINAL	431
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.6. Eastern (Area 60, Legacy EGD & Gazifère)	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	434
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.6. Eastern (Area 60, Legacy EGD & Gazifère)	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	435
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.6. Eastern (Area 60, Legacy EGD & Gazifère)	1.9.1. Aggregate									N/A - New after merge	EGI	FINAL	436
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate									N/A - New after merge	EGI	FINAL	437

Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard
412	Legacy Contamination associated with Former Manufactured Gas plants - Issues with contaminates	Jennifer Burnham	Legacy contamination associated with former manufacture gas plant which could lead to environmental impacts from contamination of the soil and groundwater.	Contaminated Soil and Water
413	Strathearne Contaminated Site Management (MECP Order)	Jennifer Burnham	Potential for contaminants (PCBs) from neighboring site move to company site and then move offsite which could impact the public.	Contaminated Soil and Water
414	Copper (Amp Fitting) Risers	Tara Kuuskman	AMP fittings are causing corrosion leaks on the adjoining copper risers. There is potential for gas migration into the building structure leading to a significant health and safety incident. The average life expectancy is 65 years with the population currently between 43 and 48 years.	Corrosion internal
416	[redacted]	Troy Kirby	[redacted]	[redacted]
420	Aerial Crossings 3rd Party Damage Hazards	Ryan Werenich	Aerial crossings may be hit during various 3rd party activities which could lead to a potential gas leak. Resulting in potential Operational, Public H&S, or Reputational impacts.	3rd party damage
421	Aerial Crossings Corrosion Hazards	Tara Kuuskman	Coating on aerial crossings may be damaged due to various hazards which could lead to corrosion initiating. Potentially undetected corrosion progressing over time may lead to a leak resulting in possible impact to operational reliability and repair costs.	Corrosion external
422	Aerial Crossings Weather & Outside Forces Hazards	Tara Kuuskman	Various ground movement hazards could potentially lead to pipe damage, pipe buckling, or mechanical fitting damage which may result in a leak repair with customer outages.	Weather and Outside Forces
423	Water Crossings 3rd Party Damage Hazards	Ryan Werenich	Water crossings may be hit during various 3rd party activities which could lead to a potential gas leak. Resulting in potential Operational, Public H&S, or Reputational impacts.	3rd party damage
424	Water Crossings Weather & Outside Forces	Ryan Werenich	Various ground movement hazards could potentially lead to pipe damage, pipe buckling, or mechanical fitting damage which may result in a leak repair with customer outages.	Weather and Outside Forces
425	Water Crossings Corrosion Hazards	Ryan Werenich	Coating on water crossings may be damaged due to various hazards which could lead to corrosion initiating. Potentially undetected corrosion progressing over time may lead to a leak resulting in possible impact to operational reliability and repair costs.	Corrosion external
426	Legacy Inside Regulators at Utilization Meter Sets with Slamshut Valve (Inlet P > 2 psig)	Tracey Teed Martin	The risk ranking driver is potential for 3rd party "pull" damage to cause the service to leak or separate at the indoor regulator inlet connection	3rd party damage
427	Farm Tap / Property Line Regulator / 1st Cut Regulator with HP or XHP inlet - Equipment Failure Hazard	Tara Kuuskman	The 1st cut regulator could potentially malfunction open due to many different causes leading to higher than intended pressure to the 2nd cut regulator. If the 1st cut failure is severe and the 1st cut overpressure protection independently fails, it could potentially mean that the maximum emergency inlet pressure of the 2nd cut regulator is exceeded leading to potential consequences at the downstream customer. The 1st cut regulator could potentially malfunction closed or partially closed due to various causes. Resulting in a customer outage and relight.	Equipment malfunction
428	Farm Tap / Property Line Regulator / 1st Cut Regulator with HP or XHP inlet - Above grade Piping and Equipment at first cut near property line - 3rd Party Damage Hazard	Tara Kuuskman	Due to various causes the piping or equipment at a farm tap installation could potentially develop an external leak accidentally releasing gas to atmosphere. The risk of external leaks is impacted by it's location. This scenario covers 1st cuts located near the property line.	3rd party damage
429	Farm Tap / Property Line Regulator / 1st Cut Regulator with HP or XHP inlet - Above grade Piping and Equipment at first cut near property line - Weather & Outside Forces Hazard	Tara Kuuskman	The 1st and 2nd cut regulator could potentially malfunction due to many different causes leading to higher than intended pressure or under pressure. Due to various causes the piping or equipment at a farm tap installation could potentially develop an external leak accidentally releasing gas to atmosphere.	Natural forces/weather
430	Farm Tap / Property Line Regulator / 1st Cut Regulator with HP or XHP inlet - Corrosion Hazard	Tara Kuuskman	The 1st and 2nd cut regulator could potentially malfunction due to many different causes leading to higher than intended pressure, under intended pressure, or external leak.	Corrosion external
431	Farm Tap / Property Line Regulator / 1st Cut Regulator with HP or XHP inlet - Construction Hazard	Tara Kuuskman	The 1st and 2nd cut regulator could potentially malfunction due to installation practices leading to higher than intended pressure, under intended pressure, or external leak.	Installation error
434	Chicago Fittings on PE Risers-Extreme Hot/Cold Weather	Tara Kuuskman	Extreme weather conditions leading to gradual "creep" failure and potential for rubber components degradation (may potentially be related to manufacturing defect)	Natural forces/weather
435	Chicago Fittings on PE Risers-Leaking Seals	Tara Kuuskman	Leaking seals caused by extreme weather conditions	Natural forces/weather
436	Chicago Fittings on PE Risers-Ground Movement	Tara Kuuskman	Potential for fuzz leak from excessive ground settlement	Natural forces/weather
437	Bridge Crossing Distribution Main - Mechanical Damage	Tara Kuuskman	External impact to a distribution bridge crossing could potentially lead to damage to pipe or pipe supports	3rd party damage

Current ID	Source
412	Legacy MGP sites are known to have had contaminating activities as part of the operations
413	Contaminants (PCBs) moved from the neighboring site and then from the site to offsite locations There is evidence that contaminants (PCBs) are found in combined sewers and Hamilton harbour.
414	The likelihood rating accounts for the leaks which peak at approximately 3,000 per year given the current replacement program and the probability of gas migration and ignition.
416	[redacted]
420	1. Aerial crossings are typically located in rural or agricultural areas which impacts the expected 3rd party activities in the vicinity of these assets. Some crossings may be in a right of way or drainage ditch. Cleaning of drainage ditch could lead to a damage. Car leaving the road could lead to a 3rd party damage. Excavation may be less likely especially in areas where its difficult to excavate due to rocky soil (which may be why it was installed as an aerial crossing instead of a water crossing). Recreational vehicles in rural areas (snowmobile or ATV) may hit crossing. **NOTE on hazards:** 3rd Party Damages could be due to Mechanical Damage (Collision - Line Strike) and Vandalism (Line Strike)
421	1. Corrosion develops over time potentially through 100% of the pipe wall. Corrosion could be initiated by a latent damage or UV light damage to pipeline coating. Some crossing may be painted instead of coated. **Note on hazards** External Corrosion could be due to Atmospheric Corrosion - Coating Damage/Degradation, External Metal Loss - Coating Damage/Degradation. Other hazards could be 3rd Party Damage - Latent Damage - Line Strike and Weather & Outside Forces - UV Light Exposure
422	1. Various ground movement hazards can expose pipe that was originally designed/constructed to be buried. **Note on hazards** Weather & Outside Forces could be due to : - Deformation due to Settlement (Wrinkle or Bend) - Flooding/Ground Movement - Ground Movement - Flooding/Ground Movement - Heavy Rain/Flood - Flooding/Ground Movement - Soil Erosion/Scouring - Flooding/Ground Movement - Subsidence - Flooding/Ground Movement
423	1. Dredging activities, drainage ditch cleaning activities, or boating activities (watercraft grounding, anchor strike, etc.) may lead to a pipe strike in a water crossing (pipeline exposure to 3rd party activity depends on the type of body of water) **NOTE on hazards:** 3rd Party Damages could be due to Latent Damage (Line Strike) and Mechanical Damage (Collision - Line Strike) Other hazards are : Weather & Outside Forces - Depth of Cover - Flooding / Ground Movement
424	1. Various ground movement hazards can expose pipe that was originally designed/constructed to be buried. **Note on hazards** Weather & Outside Forces could be due to : - Heavy Rain/Flood - Flooding/Ground Movement - Soil Erosion/Scouring - Flooding/Ground Movement - Stream Erosion - Flooding/Ground Movement - Depth of Cover - Flooding/Ground Movement **Other applicable hazard is** Construction - Wrinkle or Bend - Flooding/Ground Movement
425	1. Weather & outside forces/ground movement may expose pipe leading to potential for damage to coating and corrosion to develop over time potentially through 100% of the pipe wall. Pipeline weights may be moved over time causing damage to pipeline coating leading to similar corrosion concerns. **Note on hazards** External corrosion could be due to: - Atmospheric Corrosion - Coating Damage/Degradation - External Metal Loss - Coating Damage/Degradation
426	1. Third party "pull" damage may cause the service to leak or fully separate at the indoor regulator inlet connection (there is a chance the pull damage leak may occur outside the customer premise) 2. Failure of pressure control equipment leading to potential overpressure of downstream appliances and indoor leak from appliance. 3. Corrosion hazards to services may cause leak from service that could potentially migrate indoors. **Note on hazards** Accidental release/LOC flammable gas due to any of the following hazards: - 1st & 2nd Party Damages - Mechanical Damage - Excavation - 1st & 2nd Party Damages - Mechanical Damage - HDD - 3rd Party Damage - Latent Damage - 3rd Party Damage - Mechanical Damage - Excavation - 3rd Path Damage - Mechanical Damage - HDD - 3rd Party Damage - Vandalism - Equipment Failure - Malfunction of Control/Overpressure Protection - External Corrosion - Atmospheric Corrosion - External Corrosion - External Metal Loss
427	1. Potential debris in gas stream causes damage to soft internals of regulator orifice / seat assembly or the debris could potentially get stuck on orifice / seat causing regulator to be in a failed open state 2. Internal corrosion or material degradation could lead to broken internal component impacting pressure control (i.e. spring or mechanical linkage) causing regulator to be in a failed open state 3. Inadvertent procedural error leading to not exchanging 1st cut regulator and overpressure protection device during scheduled MXGI cycle may allow certain time dependent damage mechanisms previously listed to further progress into a failure causing regulator to fail closed 5. Inadvertent procedural error to install regulator vent pointing up leading to water ingress/corrosive environment and potential broken internal component impacting pressure control (i.e. spring or mechanical linkage) causing regulator to fail closed **NOTE on hazards:** 1. Equipment Failure - Mechanical Fitting Malfunction (Pressure Reducing Regulator Fails closed / Failure to lock-up under no flow conditions) 2. Internal Corrosion - Internal Corrosion 3. Material Degradation - Damage to Regulator Cap 4. Manufacturing defect
428	External impact or force causes leak (chance of occurrence impacted by proximity to road) **NOTE on hazards:** 3rd Party Damages could be due to Mechanical Damage (collision), Latent Damage and Vandalism Other hazards are: 1st & 2nd Party Damages could be due to Mechanical Damage (collision)
429	1. High moisture content in gas potentially leading to regulator frozen in open position impacting regulator response to downstream demand changes causing regulator to be in a failed open state 2. Vandalism, debris, or plants/animals/bugs block regulator vent from sensing atmospheric pressure leading to regulator stuck in open position or reducing relief capacity (depending on type of regulator) **NOTE on hazards:** Weather & Outside Forces could be due to Plant/Animal interference, Lightning Strike, Frost Heave, Extreme Weather, Wide Fire
430	External corrosion over time may progress through 100% of pipe wall if not remediated **NOTE on hazards:** External Corrosion could be due to Atmospheric Corrosion
431	1. Inadvertent procedural error leading to fitter potentially not installing 1st cut regulator at Farm Tap 2. Inadvertent procedural error leading to fitter not exchanging old 1st cut regulator and overpressure protection devices during scheduled MXGI cycle may allow certain time dependent damage mechanisms previously listed to further progress into a failure 3. Inadvertent procedural error to incorrectly install regulator vent pointing up leading to water ingress/corrosive environment and potential broken internal component impacting pressure control (i.e. spring or mechanical linkage) 4. Inadvertent procedural error when installing OPCO regulator (i.e. separating OPCO head from body) **NOTE on Hazards** It is related to Construction - Installation Practices.
434	1. Large and sudden temperature fluctuations have been shown to result in gradual "creep" failure mode Potential for the rubber component to degrade over time increasing potential for leaking seals or compromising pull out resistance
435	1. Large and sudden temperature fluctuations have been shown to result in gradual "creep" failure mode Potential for the rubber component to degrade over time increasing potential for leaking seals or compromising pull out resistance Approximately 105,000 fittings installed before 1987 LEGD system. Confirmation of the pull out failure hazard increases the risk associated with the hazard.
436	2. Excessive ground settlement causes additional stress on fitting
437	1. Either a car, boat, construction equipment hitting bridge or pipeline leading to damage to pipeline due to inadequate support/ protection **Note on hazards** 3rd Party Damage could be due to Mechanical damage - collision Other hazards are: 1st & 2nd Party Damages - Mechanical damage - collision

Current ID	Consequences
412	Significant contamination of soil and groundwater (most likely move with ground water or with vapor at subsurface at concentration exceeding exposure limits) with the potential of migration offsite. Cost of remediation and/or potential litigation. **NOTE on Risk Driver** - Environmental : Contaminate move with ground water or with soil vapor and cause adverse effect - offsite impact
413	PCBs from neighboring site could come on the company site then go off site (this is a specific path way moving from neighboring site to the ditch and off the site) **NOTE for consequence rankings:** E : PCBs is found in the sewage H&S : Based on exposure to public R: An order has been issued with the requirement for mitigation due to offsite contaminant F: Cost to remediate the site and civil lawsuit (The current risk ranking is before risk treatment plan, if the risk treatment plan is followed through, all cost should be recovered from the neighboring company)
414	In the rare event of an ignition there is potential for fatality.
416	[redacted]
420	1. Various types of 3rd party damages could lead to a leak and temporary repair with long term replacement 2. Various types of 3rd party damages could lead to a leak resulting in potential ignition and public H&S incident
421	1. Possible leaks due to corrosion would require repair and may result in customer losses
422	1. Possible damaged pipe due to pipe buckle or mechanical fitting damage due to ground movement hazards. May develop into a leak. Potential leaks would require repair and may result in customer losses
423	1. Potential line strikes could result in damage and potentially a leak. Would require repair and possible customer impact
424	1. Possible damaged pipe due to pipe buckling, mechanical fitting damage due to ground movement hazards/debris on bottom of water way hitting exposed line. May develop into a leak. Potential leaks would require repair and may result in customer losses
425	1. Possible leaks due to corrosion would require repair and may result in customer losses
426	Depending on leak rate, building ventilation, and room size, it is possible for indoor gas leak to build up to LFL leading to possible ignition resulting in an explosion with the potential to result in > 10 public fatalities
427	1. If overpressure protection on 1st cut also fails, higher pressure downstream to the 2nd cut regulator potentially above the maximum emergency inlet of the 2nd cut (typically 125 psig design). Internal relief venting at 2nd cut. Potential overpressure downstream leading to damage to appliance, indoor leak, and possible ignition resulting in a fire or explosion in customer premise 2. If overpressure protection on 1st cut also fails, higher pressure to downstream PE service potential overpressure resulting in a leak from fitting or pipe that may burst through soil or migrate to nearby premise with potential to build up to LFL and ignite. Resulting in a fire or explosion in customer premise 3. No gas to customer leading to trouble call, repairs to company equipment, and relighting the customer.
428	Above grade leak to atmosphere with potential ignition resulting in an outdoor fire that potentially causes a burn injury and/or property damage
429	1. If overpressure protection on 1st cut also fails, higher pressure downstream to the 2nd cut regulator potentially above the maximum emergency inlet of the 2nd cut (typically 125 psig design). Internal relief venting at 2nd cut. Potential overpressure downstream leading to damage to appliance, indoor leak, and possible ignition resulting in a fire or explosion in customer premise 2. If overpressure protection on 1st cut also fails, higher pressure to downstream PE service potential overpressure resulting in a leak from fitting or pipe that may burst through soil or migrate to nearby premise with potential to build up to LFL and ignite. Resulting in a fire or explosion in customer premise
430	Above grade leak to atmosphere with potential ignition resulting in an outdoor fire that potentially causes a burn injury and/or property damage
431	1. If overpressure protection on 1st cut also fails, higher pressure downstream to the 2nd cut regulator potentially above the maximum emergency inlet of the 2nd cut (typically 125 psig design). Internal relief venting at 2nd cut. Potential overpressure downstream leading to damage to appliance, indoor leak, and possible ignition resulting in a fire or explosion in customer premise 2. If overpressure protection on 1st cut also fails, higher pressure to downstream PE service potential overpressure resulting in a leak from fitting or pipe that may burst through soil or migrate to nearby premise with potential to build up to LFL and ignite. Resulting in a fire or explosion in customer premise 3. No gas to customer leading to trouble call, repairs to company equipment, and relighting the customer.
434	1. Possible fuzz leak resulting in leak response and minor repair with LLFA tape
435	2. Possible full pull out failure leading to potential ignition and building fire resulting in possible injury to the public
436	Possible fuzz leak resulting in leak response and minor repair with LLFA tape
437	1. Potential loss of containment leading to uncontrolled release of natural gas, possible ignition resulting in potential fire or explosion 2. Potential loss of containment leading to uncontrolled release of natural gas and leak repair resulting in potential customer loss (risk depends on time of year and system design/back feeding)

Current ID	Controls
412	- Soil and ground water samplings have been completed for former manufactured gas plants - E-PRO-111-Suspect Soils Management Program (Protect workers if they were to show up at the site) - E-PRO-104-Hazardous Waste Management Program (Same as above) - Contaminated Sites Working Group NOTE: some sites have risk assessments done and some of them do not post risks to human health and the environment.
413	Legacy UG removed underground sewer and localized contaminated soil from the site
414	Leak survey Leak Repair Emergency Response Program
416	[redacted]
420	1. Leak Survey - Crossing Inspections as part of Leak Survey SOP (Repair and replacement work identified as part of surveys) 2. Corrosion Survey SOP 3. Emergency response procedures 4. Gas is odourized for leak detection 5. Pipeline markers 6. Damage prevention program
421	1. Installation of new aerial crossing locations are typically selected based on factors evaluated during route selection process and environmental assessment during design (installation of new aerial crossings are not a typical a first choice consideration unless there are other factors which prevent alternative crossing methods) 2. Leak Survey - Crossing Inspections as part of Leak Survey SOP (Repair and replacement work identified as part of surveys) 3. Emergency response procedures 4. Gas is odourized for leak detection
422	1. Damage Prevention i.e. Call Before You Dig before dredging and for critical pipelines supervised 3rd party activities 2. Installation of new water crossings are designed with a specified depth of cover 3. Leak Survey - Crossing Inspections as part of Leak Survey SOP (Repair and replacement work identified as part of surveys) 4. Water Crossing Inspection Surveys (Repair and replacement work identified as part of surveys) 5. Emergency response procedures 6. Gas is odourized for leak detection
423	1. Installation of new water crossings are designed with a specified depth of cover 2. Leak Survey - Crossing Inspections as part of Leak Survey SOP (Repair and replacement work identified as part of surveys) 3. Water Crossing Inspection Surveys (Repair and replacement work identified as part of surveys) 4. Emergency response procedures 5. Gas is odourized for leak detection
424	1. Leak Survey - Crossing Inspections as part of Leak Survey SOP (Repair and replacement work identified as part of surveys) 2. Corrosion Survey SOP 3. Emergency response procedures 4. Gas is odourized for leak detection 5. Pipeline markers 6. Specific/additional coating design requirements for water crossings
425	1.1. Locate procedures & call before you dig. Some locations also have a waring sign for "below grade service entry" to raise public awareness to get locates before excavation. 1.2. Some locations have an excess flow valve (EFV) on service or "weak link" (transition to PE, above grade shut off valve before building entry, etc.) 2.1. Approved design and procedure to install slam shut valve overpressure protection instead of an IRV vented outdoors 2.2. Equipment inspections before introduction of gas to premise and asset replacement through MXGI program as per approved procedures 2.3. Customer appliance controls and safety shut off may be able to contain overpressure and prevent leak 3.1. Corrosion prevention program and cathodic protection 3.2. Leak Survey Applies to all scenarios: - Gas is odourized for leak detection - Building ventilation may limit gas build-up (limited effect as per minimum building codes)
426	'-Locate procedures & call before you dig. Some locations also have a waring sign for "below grade service entry" to raise public awareness to get locates before excavation. -Some locations have an excess flow valve (EFV) on service or "weak link" (transition to PE, above grade shut off valve before building entry, etc.). -Gas is odourized for leak detection -Building ventilation limits gas build-up (as per minimum building codes) -Emergency call procedures i.e. customer advised to open windows or evacuate immediately etc. depending on situation -Emergency response procedures -Leak survey may detect latent damages that eventually develop into a leak some time after initial line strike
427	- Overpressure protection on 1st cut (design requirement to eliminate common modes of failure between operating regulator and overpressure protection) - Maximum emergency inlet pressure of 2nd cut reg is 125psig and may hold pressure from less severe 1st cut failures - Overpressure protection on 2nd cut (internal relief valve IRV not sized for 1st cut full inlet pressure to 2nd cut) - Appliance safety controls and shutoff may be able to hold overpressure - Odourized gas for leak detection - Emergency response procedures - Isolation valve outside customer premise - Installation procedures with equipment operational testing step - QA program by MEC tests batches of products from manufacturer before installation to help ensure products received from manufacturer are functioning as specified
428	- Pipeline markers - Excess flow valves on some services - Odourized gas for leak detection - Emergency response procedures - Isolation valve outside customer premise, isolation valve on 1st cut, and curb valve tee - Leak survey
429	- Overpressure protection on 1st cut (design requirement to eliminate common modes of failure between operating regulator and overpressure protection) - Maximum emergency inlet pressure of 2nd cut reg is 125psig and may hold pressure from less severe 1st cut failures - Overpressure protection on 2nd cut (internal relief valve IRV not sized for 1st cut full inlet pressure to 2nd cut) - Appliance safety controls and shutoff may be able to hold overpressure - Emergency response procedures - Isolation valve outside customer premise
430	- Odourized gas for leak detection - Emergency response procedures - Leak survey
431	- Installation procedures with equipment operational testing step Overpressure protection on 1st cut (design requirement to eliminate common modes of failure between operating regulator and overpressure protection) - Maximum emergency inlet pressure of 2nd cut reg is 125psig and may hold pressure from less severe 1st cut failures - Overpressure protection on 2nd cut (internal relief valve IRV not sized for 1st cut full inlet pressure to 2nd cut) - Appliance safety controls and shutoff may be able to hold overpressure
434	1. Gas is odourized for leak detection with operations response 2. Emergency response procedures specific for Chicago fittings 3. MFR process and POLE meetings for Chicago Fittings
435	1. Gas is odourized for leak detection with operations response 2. Emergency response procedures specific for Chicago fittings - squeeze off above grade 3. MFR process and POLE meetings for Chicago Fittings
436	1. Gas is odourized for leak detection with operations response 2. Emergency response procedures specific for Chicago fittings 3. MFR process and POLE meetings for Chicago Fittings 4. Copper settlement loop
437	- Design and location of pipeline bridge crossings - Annual Bridge Crossing Inspection - Leak Monitoring - Leak Survey - Leak Repair - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan) - PUCC - Public Utility Construction Committee - Regional project updates awareness to prevent damage to utility assets

Current ID	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region
412	Detect/Mitigate Detect/Mitigate Mitigate Detect	Environmental	Environmental	5	3		
413	Mitigate	Environmental	Environmental	5	3		
414	Detect Mitigate Mitigate	Public safety	Health & Safety	2	5		
416	Prevent, Detect Prevent Mitigate	Terrorism & asset security	Operational	1	7		
420	Detect Detect Mitigate Detect Prevent Prevent, Detect, Mitigate	Public safety	Health & Safety	1	4		
421	Prevent Detect Mitigate Detect	Operational reliability	Operational	3	3		
422	Prevent Prevent Detect Detect Mitigate Detect	Operational reliability	Operational	3	3		
423	Prevent Detect Detect Mitigate Detect	Operational reliability	Operational	3	3		
424	Detect Detect Mitigate Detect Prevent Prevent	Operational reliability	Operational	3	3		
425	Prevent Mitigate Mitigate Prevent Prevent Prevent Detect Detect Mitigate	Operational reliability	Operational	3	3		
426	Detect & Prevent Prevent Detect, & Mitigate Mitigate Prevent Prevent Detect	Public safety	Health & Safety	2	7		
427	Prevent Prevent, Mitigate Prevent Prevent, Mitigate Detect Mitigate Mitigate Prevent Prevent	Public safety	Health & Safety	1	6		
428	Prevent Mitigate Detect Mitigate Mitigate Detect	Operational reliability	Financial	3	3		
429	Prevent Prevent, Mitigate Prevent Prevent, Mitigate Mitigate Mitigate	Public safety	Health & Safety	2	4		
430	Detect Mitigate Detect	Public safety	Health & Safety	2	4		
431	Prevent Prevent, Mitigate Prevent Prevent, Mitigate	Public safety	Health & Safety	1	6		
434	Detect Mitigate Prevent	Operational reliability	Financial	7	1		
435	Detect Mitigate Prevent	Operational reliability	Health & Safety	2	4		
436	Detect Mitigate Prevent Prevent	Operational reliability	Financial	2	1		
437	Prevent, Mitigate Detect Detect Detect Mitigate Prevent	Public safety	Health & Safety	1	5		

Current ID	Treatment Plan Description	Treatment Owner	Proposed Timeline
412	Develop site list and risk rank sites. - Complete site investigation at selected sites (Completed) - Contaminated site list development (Completed) - Develop risk evaluation process for contaminated site list (In draft) - Risk assess contaminated sites - develop priority action plan - Integrate the list of contaminated sites with LUG list of contaminated sites Apply risk based decision principle to prioritize resources for managing contaminated sites	Erin Nolan	Q4 2023
413	In response to the ministry order - it requires the company to address this specific path way (Contaminants moving from the north side of the site to off site locations). The company is participating in the neighboring site risk treatment plan. The plan is to cap the contaminants onsite with onsite monitoring.	Erin Nolan	Q4 2023
414	Reference copperleaf investment ID# 10262		
416			
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426	**Summary: Q1 2022** -Consider relocating indoor regulators into an external regulator room or relocate outdoors -Operations project team reviewing sites using regional approach; prioritizing below grade service entry without Excess Flow Valve (EFV) **Status: Q1 2022** -Population of concern is now 600 locations with no EFVs -Decision record completed re: EFVs as acceptable risk reduction treatment. Identified locations with no EFV and below grade service entry to build priority focus. -Identified project synergies with VSM, planning execution for 8 projects under VSM scope -Replacing and refreshing placards used for mitigation ahead of DIG SAFE month -Continue and relaunch inside meter leak survey efforts -Project team working to identify other ways to prioritize work **Status: Q4 2022** -Population of concern is now 511 locations with no EFVs	Kirby Skinn-Jones	2025
427	1. Consider including a strainer upstream of 1st cut regulators with integrated OPCO (overpressure cut off, i.e. slam shut valve) to minimize the chance of debris in the natural gas damaging or getting stuck the operating regulator and OPCO's orifice / seat assembly. 2. Consider completing a survey to define the population and locations of dual cut regulator sets (i.e. farm taps, HP/XHP meter sets, property line regulators) in order to support condition and integrity assessments.	1. Julien Samson 2. Fred Butrico	2027
428	Consider completing a survey to define the population and locations of dual cut regulator sets (i.e. farm taps, HP/XHP meter sets, property line regulators) in order to support condition and integrity assessments.	Fred Butrico	2027
429	1. Consider including a strainer upstream of 1st cut regulators with integrated OPCO (overpressure cut off, i.e. slam shut valve) to minimize the chance of debris in the natural gas damaging or getting stuck the operating regulator and OPCO's orifice / seat assembly. 2. Consider completing a survey to define the population and locations of dual cut regulator sets (i.e. farm taps, HP/XHP meter sets, property line regulators) in order to support condition and integrity assessments.	1. Julien Samson 2. Fred Butrico	2027
430	Consider completing a survey to define the population and locations of dual cut regulator sets (i.e. farm taps, HP/XHP meter sets, property line regulators) in order to support condition and integrity assessments.	Fred Butrico	2027
431	1. Consider including a strainer upstream of 1st cut regulators with integrated OPCO (overpressure cut off, i.e. slam shut valve) to minimize the chance of debris in the natural gas damaging or getting stuck the operating regulator and OPCO's orifice / seat assembly. 2. Consider completing a survey to define the population and locations of dual cut regulator sets (i.e. farm taps, HP/XHP meter sets, property line regulators) in order to support condition and integrity assessments.	1. Julien Samson 2. Fred Butrico	2027
434			
435			
436			
437			

Current ID	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
412	Q4 2022 Update -Continue environmental site investigations / remedial options for identified sites (Emma Street) -Completed annual groundwater monitoring at Brantford (Q4) -Continued work with REWS to develop reuse strategies for Brantford property -Station B REWS redevelopment in progress (and applicable soil management processes) Timeline changed from 2022 to Q4 2023. Management program goal for 2023 is to work on a contamination site plan - 5/2/2023	- **H&S (Worker)**: Worker H&S if working at site L5C1 Low - **H&S (Public)**: Contaminate would move with ground water but not impacting drinking water. More credible case is contaminated vapor getting into someone's house, and people are exposed to vapor. L3C3 Low - **Reputation**: In case of public H&S issue, regulator could write an order L3C3 Low - **Reputation** : In case of offsite impact, regulatory impact L4C3 Medium - **Financial** : Cost to investigate and clean up cost L5C3 Medium	MP-03: Environmental	2023-05-02
413	Timeline changed from 2022 to Q4 2023. Management program goal for 2023 is to work on a contamination site plan - 5/2/2023	Reputational and Financial same as Environment RR. H&S (P) : C3, L1, Low NOTE: Financial risk is based on the remediation cost if the contaminants move offsite after risk treatment plan.	MP-03: Environmental	2023-05-02
414	Risk Owner Updated from S.K. August 1 2023		MP-05: Integrity	2023-08-01
416		H&S L1, C6, RR Medium	MP-06: Security	2021-06-23
420	Risk Owner Updated from A.S. August 1, 2023	1.1. Operational L3, C3, RR Low 1.2. Reputational L3, C3, RR Low 2.1. Public H&S L1, C4, RR Low 2.2. Reputational L2, C4, RR Low	MP-05: Integrity	2023-08-01
421	Risk Owner updated from A.S on August 1, 2023	1.1. Operational L3, C3, RR Low 1.2. Financial L3, C2, RR Low	MP-05: Integrity	2023-08-01
422	Risk Owner Updated from S.K. August 1 2023	1.1. Operational L3, C3, RR Low 1.2. Financial L3, C2, RR Low	MP-05: Integrity	2023-08-01
423	Risk Owner Updated from A.S. August 1, 2023	1.1. Operational L3, C3, RR Low 1.2. Financial L3, C3, RR Low	MP-05: Integrity	2023-08-01
424	Risk Owner Updated from S.K. August 1 2023	1.1. Operational L3, C3, RR Low 1.2. Financial L3, C3, RR Low	MP-05: Integrity	2023-08-01
425	Risk Owner Updated from S.K. August 1 2023	1.1. Operational L3, C3, RR Low 1.2. Financial L3, C3, RR Low	MP-05: Integrity	2023-08-01
426	Risk owner change from Mike Wagle to Tracey Teed Martin - 06/20/2022 Treatment Owner change from Kirby Skinn-Jones to Matthew Watson 8/15/2022 Treatment Plan Updated 1/31/2023 Treatment Owner changed to Kirby Skinn-Jones 2/8/2023 Q1 2023 Update: -Population of concern is now 502 locations with no EFVs -Project team identified locations with no EFV and below grade entry for priority focus and currently working with Risk Services to initiate formal risk evaluation on review of above ground shutoffs. -Project team working to execute and to continue to identify other ways to prioritize work, including VSM overlap, municipal reconstruction and regional maintenance -This includes a risk evaluation to review the use of above ground shutoff as a possible mitigation	One RR only	MP-01: Asset	2023-02-08
427	Note that the term "farm tap" has been used differently between LEGD and LUG. Through integration, it is expected that a new common terminology will be decided on going forward. The risk register would need to be updated / reviewed when the new common terminology is available. DIMP will be inspecting all of these reg sets over the next 5 years so we will have a defined population by 2027 Risk Owner updated from A.S on August 1, 2023	Operational: L2 C2	MP-05: Integrity	2023-08-01
428	Note that the term "farm tap" has been used differently between LEGD and LUG. Through integration, it is expected that a new common terminology will be decided on going forward. The risk register would need to be updated / reviewed when the new common terminology is available. DIMP will be inspecting all of these reg sets over the next 5 years so we will have a defined population by 2027 Risk Owner updated from A.S on August 1, 2023	Public H&S: L2 C4	MP-05: Integrity	2023-08-01
429	Note that the term "farm tap" has been used differently between LEGD and LUG. Through integration, it is expected that a new common terminology will be decided on going forward. The risk register would need to be updated / reviewed when the new common terminology is available. DIMP will be inspecting all of these reg sets over the next 5 years so we will have a defined population by 2027 Risk Owner updated from A.S on August 1, 2023	Operational C2 L2	MP-05: Integrity	2023-08-01
430	Note that the term "farm tap" has been used differently between LEGD and LUG. Through integration, it is expected that a new common terminology will be decided on going forward. The risk register would need to be updated / reviewed when the new common terminology is available. DIMP will be inspecting all of these reg sets over the next 5 years so we will have a defined population by 2027 Risk Owner updated from A.S on August 1, 2023	Financial: L3 C3	MP-05: Integrity	2023-08-01
431	Note that the term "farm tap" has been used differently between LEGD and LUG. Through integration, it is expected that a new common terminology will be decided on going forward. The risk register would need to be updated / reviewed when the new common terminology is available. DIMP will be inspecting all of these reg sets over the next 5 years so we will have a defined population by 2027 Risk Owner updated from A.S on August 1, 2023	Public H&S: L2 C2	MP-05: Integrity	2023-08-01
434	Risk Owner Updated from S.K. August 1 2023		MP-05: Integrity	2023-08-01
435	Risk Owner updated from A.S on August 1, 2023		MP-05: Integrity	2023-08-01
436	Risk Owner updated from A.S on August 1, 2023		MP-05: Integrity	2023-08-01
437	Risk Owner Updated from S.K. August 1 2023	Operational L1, C5, Low	MP-05: Integrity	2023-08-01

First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version	Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard	Source	Consequences	Controls	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate									N/A - New after merge	EGI	FINAL	438	Bridge Crossing Distribution Main - Vandalism	Tara Kuuskman	Vandalism incident at a distribution bridge crossing could potentially lead to damage to pipe or pipe supports	Security property sabotage/vandalism	1. Pipe may be affixed to/used as support if inadequately protected **Note on hazards** Under MP-05 this is classified as 3rd Party Damage - Vandalism	1. Potential damage to pipeline resulting in minor repairs to coating or supports	- Annual Bridge Crossing Inspection - Leak Monitoring - Leak Survey - Leak Repair - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan)	Detect Detect Detect Mitigate Mitigate	Operational regulation	Financial	3	3						Risk Owner Updated from S.K. August 1 2023		MP-05: Integrity	2023-08-01
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate									N/A - New after merge	EGI	FINAL	439	Bridge Crossing Distribution Main - Improper Construction Practices	Tara Kuuskman	Improper or historic construction practices could potentially lead to damage to pipe or pipe supports	Construction defect	1. Defective pipe connection 2. Inadequate support or hangers/lack of expansion joint leading to additional stress to pipe due to historic construction practices 3. Inadequate support or hangers/lack of expansion joint leading to pipe deformation due to historic construction practices **Note of Hazard** Construction issues can be due to: - Defective branch connection / joint - Installation practices - Wrinkle bend or buckle	1. Potential loss of containment leading to uncontrolled release of natural gas leak from flange or connection (typically C leaks) resulting in pipeline repairs. May involve using specialized tools to make repairs.	- C&M manual installation procedures including QA checks/pressure testing and worker certification requirements - Annual Bridge Crossing Inspection - Leak Monitoring - Leak Survey - Leak Repair - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan)	Detect Detect Detect Detect Mitigate Mitigate	Operational reliability	Financial	2	3						Risk Owner Updated from S.K. August 1 2023		MP-05: Integrity	2023-08-01
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate									N/A - New after merge	EGI	FINAL	440	Bridge Crossing Distribution Main - Corrosion	Tara Kuuskman	Corrosion damage to bridge crossing pipe or hangers could develop over time	Corrosion external	1. Coating degradation or disbondment leading to corrosion over time. Corrosion may be impacted by road salt on bridge and ability/access to inspect pipeline condition on bridge crossing 2. Corrosion to supports or hangers leading to additional stress on pipeline if supports fail **Note on hazards** External Corrosion could due to Atmospheric Corrosion / External Metal Loss **Other applicable hazard** Weather and Outside Forces - UV light 3rd Party Damage - Latent damage	1. Potential loss of containment leading to uncontrolled release of natural gas and leak repair resulting in potential customer loss (risk depends on time of year and system design/back feeding) 2. Potential loss of containment leading to uncontrolled release of natural gas leak from flange or connection resulting in pipeline repairs. May involve using specialized tools to make repairs.	- Annual Bridge Crossing Inspections - May not have been followed historically which is driving the current likelihood. Due to recent changes, inspection programs have become more effective and would likely need to revisit ranking when new information/data is available - Leak Monitoring - Leak Survey - Leak Repair - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan)	Detect Detect Detect Mitigate Mitigate	Operational reliability	Operational	4	4						Risk Owner Updated from S.K. August 1 2023	Financial L4, C4, Medium	MP-05: Integrity	2023-08-01
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate									N/A - New after merge	EGI	FINAL	441	Bridge Crossing Distribution Main - Weather & Natural Forces	Tara Kuuskman	Flooding events may expose pipe that should be buried or cause high water level/debris to strike the bridge crossing	Weather and Outside Forces	1. Erosion of riser cover where banks subject to flooding 2. Flooding with high river level/debris floating down river could potentially strike pipe or hangers **Note on hazards** Weather and Outside Forces could be due to Heavy rain / Flood and Soil Erosion/Scouring	1. Potential damage to coating, pipeline, or hangers resulting in repairs and possible customer loss	- Annual Bridge Crossing Inspection - Leak Monitoring - Leak Survey - Leak Repair - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan)	Detect Detect Detect Mitigate Mitigate	Operational reliability	Operational	3	3						Risk Owner Updated from S.K. August 1 2023	Financial L3, L3, Low	MP-05: Integrity	2023-08-01
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										N/A - New after merge	EGI	FINAL	442	Bridge Crossing Distribution Main - Fitting Failure	Tara Kuuskman	Fitting failure could potentially occur due to one of the previously listed hazards	Equipment malfunction	1. Leak from unsupported mechanical coupling potentially due to any of the previous hazards already listed? E.g. corrosion of hangers, vandalism, flooding / erosion of river banks, flooding / debris down river impacts hangers or coupling, vibrations from road traffic, etc. **Note on hazard / potential hazard** Mechanical Fitting Malfunction	1. Potential loss of containment leading to uncontrolled release of natural gas and leak repair resulting in potential customer loss (risk depends on time of year and system design/back feeding) 2. Potential loss of containment leading to uncontrolled release of natural gas leak from flange or connection resulting in pipeline repairs. May involve using specialized tools to make repairs.	- Annual Bridge Crossing Inspections - May not have been followed historically which is driving the current likelihood. Due to recent changes, inspection programs have become more effective and would likely need to revisit ranking when new information/data is available - Leak Monitoring - Leak Survey - Leak Repair - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan)	Prevent Detect Detect Mitigate Mitigate	Operational reliability	Operational	4	4						Risk Owner Updated from S.K. August 1 2023	Financial L4, C4, Medium	MP-05: Integrity	2023-08-01
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										N/A - New after merge	EGI	FINAL	443	PE Fusion (Saddle Fusion integrity)	Tara Kuuskman	Possible errors during construction procedure could lead to PE pipe failure (fusion integrity issue) and leak	Incorrect operation	1. Saddle Application Tool (SAT) was operating outside of application pressure specifications - lower than intended pressure 2. Saddle Application Tool (SAT) was operating outside of application pressure specifications - higher than intended pressure 3. Fusion iron temperature was operating outside of specifications - lower than intended temperature 4. Fusion iron temperature was operating outside of specifications - higher than intended temperature 5. PE fusion tools are not maintained and missing bolts 6. PE fusion tools are not maintained and the alignment pins are bent 7 .Fitting is not properly placed on the pipe (i.e. misaligned - twisted on or moved) 8. Peeler tool is too dull, too sharp, used incorrectly, or improper tool used 9. PE pipe or fitting is exposed to high ambient temperatures (i.e. direct sunlight) before fusion 10. PE pipe or fitting is exposed to low ambient temperature before fusion 11. Fusion iron is left longer than specified on PE 12. Fusion iron is not left long enough per specifications on PE 13. Foreign material or moisture on the PE that is not removed before fusion 14. Two dissimilar PE types are used in a fusion 15. Damaged pipe or fittings are used in a fusion 16. Specified cooling time after a fusion is not allowed for 17. Too much time between removal of heater tool and addition of fitting **NOTE on Hazards / Potential Hazards** Additional hazards: Operation error, Material defect	Possible compromised -fusion (service fitting does not properly adhere to the main) leading to potential latent failure gas release. Gas release can potentially migrate, ignite, resulting in a fire with potential public fatalities at a single family home, multi-unit building (MUB), or high density commercial	1. PE Fusion Manual - C&M Manual procedures 2. PSI or Technical Field Specialists may be on site to perform QA check 3. Focused audit of calibration 4. Operator qualification with annual competency review 5. High volume punch tee fittings are not approved (limits potential leak size) 6. Gas odourised for leak detection 7. Emergency response procedures	- Prevent - Detect - Prevent - Prevent - Prevent - Detect - Mitigate	Public safety	Health & Safety	2	6			1. Consider calibration requirements of pressure gauges to help ensure correct pressure is applied to avoid potential cold fusion latent failures. Consider the upper and lower limits of allowable calibration of gauges. Ongoing as per procedure integration initiative. 2. Review the ASTM requirements for pressure application throughout the heat application cycle. Ongoing as per procedure integration initiative. 3. Consider daily maintenance requirements of SAT and gauge to help ensure correct pressure is applied to avoid potential cold fusion latent failures. Ongoing as per procedure integration initiative. 4. Consider providing technicians with a higher accuracy, additional pressure gauge in order to confirm fusion tools are within specification (the same hydraulic pressure gauge as the auditors). Consider training requirements to use new gauge. 5. Review allowable fitting design regarding pipe wall thickness and potential gap between fitting and pipe before fusion. The issue is an investigation completed in 2018 revealed that thinner walled PE pipes had a higher rate of failure and a research report identified that the larger the gap between fitting and pipe the greater the chance of blowout failure. 6. Consider temperature calibration requirements for fusion irons. The issue is the temperature measurement may not be consistent across the fusion iron. Another issue is the temperature measurement may occur on the heating block instead of the face of the tool that would be in contact with the pipe potentially resulting in inconsistent temperature readings (could potentially occur due to build up of material on tool or one defective coil out of two). Review the time between calibrations. 7. Consider adding more prescriptive maintenance and daily checks for PE fusion tools regarding missing or loose bolts, bent alignment pins, etc. in the procedures. 8. Review if an additional redundant QA sign off is a worthwhile additional risk control for PE fusions after the other risk treatment plans are implemented. Consider as a continuous improvement idea. 9. Consider if electro fusions can replace heat fusions to reduce the chance of failure. An electro fusion only pilot study was started in the Eastern Region (Ottawa). Follow up on the results of pilot study. 10. Review approved peeler tools. One potential issue is using a flat peeler on around pipe since it could lead to changing the shape of the pipe or removing too much material. Newer tools go around the pipe circumference and are easier to use correctly/scrape the correct amount. Would be included in the procedure integration. 11. Consider including the engineering memo into procedure regarding keeping PE pipe in shade before fusions to limit potential PE fusion blowouts due to high temperature issues 12. Review how the technician is supposed to correctly time PE fusions. A potential concern is lone worker fusions require the one technician to use both hands for other tasks and still expected to correctly time actions.	1. Maurice Sardari 2. Maurice Sardari 3. Maurice Sardari 4. Maurice Sardari 5. Maurice Sardari 6.Maurice Sardari & Jo Milo 7. Maurice Sardari 8. Fred Butrico 9.Maurice Sardari & Fred Butrico 10.Maurice Sardari 11.Maurice Sardari 12.Maurice Sardari	Ongoing	05/31/2021 (M. Hildebrand) updated Controls categories and emailed Fred B about treatment plan timelines Updated Shawn K as Risk Owner as per his approval 20210608 (Kathy S) Treatment Plan due date updated as per Maurice Sardari's email Timeline changed from end of 2022 to ongoing - 5/2/2023 Risk Owner updated from S.K. August 1 2023	Health and safety: L1, C6 Medium	MP-05: Integrity	2023-08-01
1. Natural gas distribution	1.1. Pipe	1.1.2.Distribution Main > 30% SMYS	1. Ontario Distribution	1.3. GTA West & Niagara (Areas 20, 50, & 80)	1.3.2. 50 – Barrie									N/A - New after merge	EGI	FINAL	446	NPS 8 Barrie to Collingwood - Customer addition exceeds current system capacity – Cumulative additions between 2018 and 2026.	Mark Maxwell	Current pressure of NPS 8 Barrie to Collingwood is at 400 psi. Since the business has not made a formal decision on not adding customers to the system, continues addition of customers could exceed current system capacity leading to potential loss of existing customers	Operate beyond allowable limits	Continuous adding customer to networks feeding from NPS 8 Barrie to Collingwood, the system is approaching its limit	Potential for loss of gas supply to customers. NOTE: Consequence is based on a typical outage in the scope of the analysis.	Emergency response	Mitigate	Operational reliability	Operational	2	4			Pressure elevation of sections 1,2 and 3, and associated work. Upgrade 9 stations, reinforce 11 branch connections, elevate pressure to 500 psig. Refer to Copperleaf investment #500705 - Pressure elevation for network 5301	Mike Miller	2024	Risk owner change from Bike Balkanci to Mark Maxwell, old treatment plan description moved to comments. New treatment plan implemented along with hyperlink to copperleaf investment. -Proposed timeline for treatment plan given as 2023 - 6/20/2022 Summary: Q1 2022 -Keep the Barrie and Collingwood line (NPS 8) on Network Analysis watch list to monitor future demand. -Pressure Elevation Status: Q1 2022 -DOE has confirmed the need for more gas -MP-02 Emergency Management considering building an emergency exercise around this line for 2022 -The recommended solution is pressure elevation of the entire pipeline. The other option was to elevate the pressure for a part of the pipeline which would be used as a contingency plan if costs exceed budget. It was also determined that a full pipeline replacement is not economically feasible per EBO 188. Q4 2022 Update: -Capital investment to complete pressure elevation deferred from 2023 to 2024 due to capital constraints -DOE and Engineering have agreed to elevate the line to 420 PSI in 2023, followed by full elevation to 500 PSI in 2024 -Risk re-evaluation to be scheduled for Q1, 2023 Based on the decision made in the re-evaluation workshop the context of the risk has been updated to confirm the completion of Engineering assessment to verify the Maximum Operating Pressure (MOP) to 500PSI. The likelihood of not completing the Engineering Assessment has been updated to 2 (known to have happened once in the industry) bringing down the overall risk ranking to a Low (L2C4) from the previous High Risk Ranking (L6C4). It should also be noted that moving forward, similar	Reputational L6, C4, RR High	MP-01: Asset	2023-07-12
3. Aggregate			3. Aggregate											N/A - New after merge	EGI	FINAL	447	Concerns with existing Dresser repair Sleeves	Todd Piercey	Legacy installations of Dresser repair sleeves on >30% SMYS pipelines may have used steel and manufacturing practices that do not meet internal Enbridge and Industry established standards. Primarily installed on 12" diameter or less pipelines.	Material defect	The sleeves may have reduced material properties that are not adequate to retain pressure in the event that the defects they are used to repair deteriorate further leading to a loss of primary containment requiring the sleeves to retain pipeline pressure.	Potential loss of containment leading to uncontrolled release of natural gas. Most likely failure mode is a leak.	"The manufacturing process has now been fully reviewed by Engineering and additional manufacturing and testing protocols have been prescribed and accepted by Dresser, this should eliminate any concern moving forward. Legacy installations are still in-line-inspected on set frequencies and defects can continue to be assessed to determine if they are continuing to worsen."	Prevent	Public safety	Health & Safety	2	4							Operational: L2 C4 Financial: L2 C4	MP-01: Asset	2021-06-29
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation												LUG	FINAL	448	Inefficient Communication between gas control room personnel and STO personnel	Clancy O'Hara	Communication intent changed through multiple layers with incorrect (or no) action being taken. GDS could over or under deliver (even shut-in wrong facility). If interconnect performing work on facilities downstream of parkway and need lower SWP, GDS may overpressure their system.	Operator errors	Multiple layers of communication between gas control room personnel and STO personnel resulting in changed information	If interconnect performing work on facilities downstream of parkway and need lower SWP (safe working pressure), GDS may overpressure their system.	i) Control Room applications (Shift Log, Call Log, OSB) ii) SCADA monitoring and controller response iii) Standard Operating Protocols Additional Controls: '- Provide more direct communication paths (i.e... GC-Parkway) and/or change AORs to be reflective of control room accountabilities/responsibilities - Consider allowing control rooms read-only access to other control room shift logs (i.e. rates section)	Detect Detect	Operational reliability	Health & Safety	4	5						06/27/2022 - changed red text (GDS text in description and consequence) from July 2021 to black and reuploaded	One RR only	MP-08: Control Room	2022-06-27
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation												LUG	FINAL	449	Worker fatigue in control room leading to distribution system risk	Clancy O'Hara	a) **Distribution System** - Failing to appropriately control and/or monitor to recognize escalating conditions	Operator errors	Incoming controller didn't receive adequate sleep and came in to shift tired	May lead to emergency pipeline conditions - freeze off (lose customers)... freeze open (over pressure)	i) Hours of service rules and deviation reporting via CR applications ii) Gas Control Manual Shift Change procedure - must acknowledge fit for duty ii) Annual workload assessments iii) Alarm reviews (daily, weekly) iv) Annual fatigue training through industry-leading experts, "Circadian" v) Mitigations to minimize fatigue exposure (ref CRM Program) vi) 2nd person overnight to cooperate operational decisions vii) rest area to refresh	Prevent Prevent Detect Detect Prevent Mitigate	Operational reliability	Operational	1	4							Reputational: L1 C4 Low	MP-08: Control Room	2021-06-07
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation				LUG	Duplicate	455	SCADA Misinformation	Proposed: Clancy O'Hara	Wrong RTU load copied Example - wrong data being displayed to controller. This could be related to field tech training.	Equipment malfunction		LUG	FINAL	450	Worker fatigue in control room leading to transmission system risk	Clancy O'Hara	b) **Transmission System** - Failing to appropriately control and/or monitor to recognize escalating conditions that may lead to emergency pipeline conditions - Low line pack (lose customers)... compressor set point wrong or valving wrong (over pressure)	Operator errors	Incoming controller didn't receive adequate sleep and came in to shift tired	May lead to emergency pipeline conditions - Low line pack (lose customers)... compressor set point wrong or valving wrong (over pressure)	i) Hours of service rules and deviation reporting via CR applications ii) Gas Control Manual Shift Change procedure - must acknowledge fit for duty ii) Annual workload assessments iii) Alarm reviews (daily, weekly) iv) Annual fatigue training through industry-leading experts, "Circadian" v) Mitigations to minimize fatigue exposure (ref CRM Program) vi) 2nd person overnight to cooperate operational decisions vii) rest area to refresh	Prevent Prevent Detect Detect Prevent Mitigate	Operational reliability	Operational	1	6							Reputational: L1 C6 Medium	MP-08: Control Room	2021-06-11
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation												LUG	FINAL	452	Overwhelming alarms and incoming calls causing missed priorities	Clancy O'Hara	Controller on-duty faced with overwhelming alarms coming in together with incoming calls part way through shift	Operator errors	Controller on-duty faced with overwhelming alarms coming in together with incoming calls part way through shift	Missed priorities that could lead to emergency pipeline conditions	i) ALARM MANAGEMENT PLAN ii) GNS - send low priority alarms to responsible field personnel ii) Alarm Response Procedure to help streamline and prioritize iii) Roles and Responsibilities and Gas Control Manual training thereof (awareness, request help) iv) Alarm reporting and review by management team vi) Annual workload study to collect alarm frequency and how impacting controllers vii) 2nd person to share excess workload (i.e. ERX or power) viii) rest area to refresh	Prevent Mitigate Prevent Prevent Detect	Operational reliability	Reputational	3	4								MP-08: Control Room	2021-06-11
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation				LUG	DRAFT	455	SCADA Misinformation	TBD	Wrong RTU load copied Example - wrong data being displayed to controller. This could be related to field tech training.	Equipment malfunction		LUG	FINAL	455	SCADA Misinformation	Clancy O'Hara	Wrong RTU load copied Example - wrong data being displayed to controller. This could be related to field tech training.	Equipment malfunction	Information being monitored or commands/responses between control room and remote devices are incorrect potentially leading to loss of supply and/or equipment damage	Supply shortage or potentially injury (over pressure incident)	i) P2P Procedures ii) Commissioning Procedures iii) Control Room Applications (PCM)	Prevent	Operational regulation	Operational	2	3								MP-08: Control Room	2021-06-11
2. Pipeline transportation of natural gas	2.1. Station	2.1.3. Station Aggregate	2. Ontario Transportation												LUG	FINAL	456	On-site awareness	Clancy O'Hara	Station technician visits telemetered station without gas control's knowledge	Incorrect operation	Gas Control could see alarms or conditions which may cause the Gas Controller to take remote action that could cause harm to the station technician.	Gas controller could take remote action that could cause harm to the station technician.	i) DOM Procedures (Dist. Ops Manual) ii) CRM LMS Module requirement iii) GDS Library	Prevent	Operational reliability	Reputational	3	3								MP-08: Control Room	2021-06-05
2. Pipeline transportation of natural gas	1.5. Aggregate	2.4.5. Transportation Aggregate	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate										LUG	FINAL	457	SCADA Misinformation-Documentation Error	Clancy O'Hara	Incorrect/unknown/ inconsistent/out of date data that could cause set limits to be incorrect, allowing too low/too high pressures on the system.	Incorrect operation	- Schematics & Screens out of date or incorrect. - Underlying data inconsistent, incorrect or unavailable. - STO has no SAP PM so no known MOP or MIN pressures. Set limits may be incorrect due to lack of design information. - Naming: One department calls it One thing and Controllers know it as something else. -Information being monitored or commands/responses between control room and remote devices are incorrect potentially leading to loss of supply and/or equipment damage	May cause the Gas Controller to take action that could cause harm. Limits may allow too low or too high pressures on the system.	i) P2P Procedures ii) Commissioning Procedures iii) Parameter Change Management	Prevent	Operational reliability	Operational	3	4				Leslie Reitsma		Additional Controls to be Considered: Standardize limits similar to how we standardize priorities (one storage place, standard process)	Operational: Low L2 C3 Reputational: L4 C3 Medium	MP-08: Control Room	5/19/2021
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation												LUG	FINAL	459	Reliance on Elevators	Clancy O'Hara	Controller trapped in elevator causing facilities to be unmonitored	Equipment Malfunction	Controller trapped in elevator (for control rooms located on higher floor)	Facilities unmonitored/uncontrolled during lone shift	i) Security procedures (have the on-call list - ref Person Down...) ii) cell phone with call-forwarded can contact Dawn to temporarily take control	Prevent Mitigate	Operational reliability	Operational	2	4						Additional Controls to be Considered: Relocate control room to more-accessible floor (no elevator required) 2 Controllers on... Currently assessing future locations for control room environment		MP-08: Control Room	2021-06-11
2. Pipeline transportation of natural gas	1.5. Aggregate	2.4.5. Transportation Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.11.1. EGI Aggregate										LUG	FINAL	460	Lack of communication of changing technician site accountabilities	Clancy O'Hara	Technician site accountabilities changed and not communicated, could result in delayed controller responses	Operator errors	Technician site accountabilities changed (retirements, new hires) and not communicated to control room	Delayed response times in emergency situation vs a nuisance to track down when busy with other issues occurring in the control room	i) Tech conferences (to remind of protocol) ii) periodic attendance at Tech Mgr. meetings iii) periodic reviews with district information	Prevent Detect	Operational reliability	Financial	4	3						Additional Controls to be Considered: Access to District lists/vacation calendars? On call technicians to filter through calls, risk will be mitigated in Q4 2021	Reputational: L4 C3 Medium	MP-08: Control Room	2021-06-28
1. Natural gas distribution	1.5. Aggregate		1. Ontario Distribution												LUG	FINAL	461	Mainline Pressure Sensor Location	Clancy O'Hara	Misinterpretation of alarms (ROC) on pressure sensor located on power gas supply line.	Operator errors	Alarms go off (ROC) on pressure sensor located on power gas supply line.	Misinterpreting alarm and making wrong decision (close valve and cut supply or leave open and blow gas to atmosphere - or burn)	i) Gas Control Manual Section 3 (MLBM Response Procedure) Additional Controls to be Considered: i) Gas Control Manually change of where sensor locations go ii) Subsequent field application of above	Mitigate	Operational reliability	Reputational	1	5								MP-08: Control Room	2021-06-23
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation												LUG	FINAL	462	Control Room Unsafe	Clancy O'Hara	Unsafe control room causes emergency evacuation	Response to hazardous situations (e.g. emergencies)	Emergency evacuation declared for 50 Keil Dr	- remote monitoring/controlling capability lost - large system for Dawn to look at temporarily during relocation	i) Gas Control Manual Section 11 ii) BCP iii) IC Plan iv) back-up facility v) relocation testing annually	Prevent Prevent Prevent Mitigate Prevent	Operational reliability	Reputational	1	5								MP-08: Control Room	2021-06-11
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation												LUG	FINAL	463	Controller accident enroute to work for shift change or home after shift change	Clancy O'Hara	Incoming controller didn't make it in to work due to accident enroute.	Worker fatigue	Incoming controller didn't make it in to work due to accident enroute.	Outgoing controller is at increased risk of fatigue at the end of shift and could make poor decision/action causing equipment/people harm.	i) Gas Control Manual Section 9 ii) more controllers available to come in iii) 2 controllers on shift	Prevent Prevent Prevent	Operational reliability	Operational	1	5							L3,C3	MP-08: Control Room	2021-06-11
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation												LUG	FINAL	464	Misinterpretation of false alarms	Clancy O'Hara	Misassumption that real alarm is a nuisance/false alarm creating unsafe conditions	Operator Errors	Too many Nuisance & False alarms due to no or low flow conditions.	May assume the alarm is another nuisance or false alarm when it is real. "Cry Wolf" scenario. Create unsafe condition - no odourant being injected and unodourized gas going to a town.	i) Alarm Management ii) CAP questions iii) top 20 report best efforts (weekly high volume alarm report) iv) frozen alarm on flow (3 - 4 per day to advisor)	Prevent	Public safety	Health & Safety	2	5							L1,C6	MP-08: Control Room	2021-06-11
2. Pipeline transportation of natural gas	2.4. Storage	2.4.5. Transportation Aggregate	2. Ontario Transportation												LUG	FINAL	466	Unverified Point Left Without Verification	Clancy O'Hara	Unverified point left for days that could be misinterpreted/missed	Operator Errors	Point left unverified for days without verification.	Gas Controller could misinterpret white alarm colour as suppressed and miss critical alarms. Failed to note token.	i) Alarm management ii) Gas Control Manual training ii) Advisor role ensuring that appropriate commissioning occurs	Prevent	Operational reliability	Operational	1	4								MP-08: Control Room	2021-06-18
2. Pipeline transportation of natural gas	1.5. Aggregate	2.4.5. Transportation Aggregate	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate										LUG	FINAL	467	Gas Controller Distraction	Clancy O'Hara	Missed alarms/conditions/phone calls due to controller being distracted	Operator errors	Controller becomes pre-occupied with other events (not work-related, somewhat work-related but not a priority - example impromptu meetings with other personnel in control room... or preparing meals... or applying a fatigue mitigation tactic)	Missing alarms/conditions/phone calls potentially leading to emergency pipeline conditions	i) Audible and visual (flashing) alarms ii) Controlled access to control room iii) Annual workload study to identify distractions and determine actions if required iv) VM not activated... rings until answered	Detect Prevent Prevent Mitigate	Operational reliability	Operational	1	3								MP-08: Control Room	6/18/2021
2. Pipeline transportation of natural gas	1.5. Aggregate	2.4.5. Transportation Aggregate	1. Ontario Distribution	1.11. EGI Aggregate	1.11.1. EGI Aggregate										LUG	FINAL	469	Inadequate Procedure Maintenance	Clancy O'Hara	Procedure not updated causing incorrect response	Incorrect operation	Gas control manual not updated with latest information/situation	Incorrect response leading to abnormal/emergency conditions	i) Annual reviews conducted ii) Gas Control Manual Training iii) Competency Assurance Program	Detect Prevent	Operational reliability	Operational	1	3							Reputational: L1 C3 Low	MP-08: Control Room	6/18/2021
2. Pipeline transportation of natural gas	2.4. Storage	2.4.5. Transportation Aggregate	2. Ontario Transportation												LUG	FINAL	470	Backup Site Elements not Functional	Clancy O'Hara	Missed calls due to controller's devices not working	Equipment malfunction	Controllers' desktops, monitors & phones at backup site have been changed or not working.	Gas Controller could miss alarms or make an incorrect decision if tools are unavailable. May miss incoming calls.	i) BCP Test - checks	Detect	Operational reliability	Financial	4	1							Reputational: L4 C1 Low	MP-08: Control Room	2021-06-14
1. Natural gas distribution	1.1. Pipe	1.1.1. Distribution Main	1. Ontario Distribution	1.2. Southwest (Windsor/Chatham, Sarnia/London)	1.2.4. Div_04 - London									N/A - New after merge	EGI	FINAL	471	Creek Crossing Exposures on Port Stanley Lateral	Andrea Seguin	6 meter of exposed pipeline at the creek could be subjected to impact of debris during high water situation (specifically in spring time), if there is mechanical fitting in the near vicinity of the pipe, it could potential let go leading to release of gas	Weather and Outside Forces	Weather and Outside Forces - Soil erosion, possible course of creek changed with time over many years, leading to washout of the ground on the hill If there is mechanical fitting in the near vicinity of the pipe, it could fail NOTE : Assume 1/10 yrs. flood **Note on hazards** Weather and Outside Forces could be due to Heavy rain / Flood and Soil Erosion/Scouring	Cold season: Assuming impact to 1/3 of customers at St Thomas equivalent to 3598 customers, all customers at Port Stanley, plus one hospital at St Thomas, St Jos Health Care facility and a green house on the east west line. Note: Assuming St. Thomas can be isolated and back fed to certain extend.	Leak Survey (Annual) + Repair work Emergency response NOTE : Water level is currently not monitored on a regular basis	Detect Mitigation	Operational reliability	Operational	4	6			Short Term: Increase in leaks survey, valve inspections, field assessment and emergency response plan developed Long Term: Pipe replacement	Aron Murdoch	2025	Risk Owner and Due Date Updated April 28 2023 Q1 2023 Update: Treatment plan is captured in the 2023 – 2032 AMP Budget has been approved for some preliminary works (Geotech, Drafting) to commence in 2023 Project management activities (Leave to Construct project) deferred from 2023 Integrity Management to determine Risk Assessment approach pending outcome of St. Laurent. Risk Owner changed from Murray Costello to Andrea Seguin (2/27/2023)		MP-01: Asset	7/27/2023
2. Pipeline transportation of natural gas	2.6. Aggregate	2.2.2. Dehy Facility	3. Aggregate	1.2. Southwest (Windsor/Chatham, Sarnia/London)	1.2.5. Southwest Aggregate										LUG	FINAL	472	Moisture Exceeds Gas Quality Standards at Dawn	Clancy O'Hara	Dawn Dehydration unit & pipeline system cannot supply sufficient dry gas to customers as demanded leading to financial impacts	Off spec gas	1. High moisture content in Upstream Pipeline 2. Upstream supply cannot support non-transmission Design Day Storage 3. Upstream Supply Storage By-Pass cannot meet gas quality standards 4. Facility capacity moisture transmission is not as modelled 5. All dehydration facilities are not operational 6. Utilization forecast is not accurate	Customers are not supplied with gas at a max of 4 lbs/mmcf causing financial, operational & reputational impacts: Worst case financial impact: $100MM/ Likely Case: $50MM Operation Impact: Worst case: 1 week to 1 month (52)/Likely Case: 1 day to 1 week outage (36) Operation Impact: Worst-case: 6 month shutoff of "firm demand"	Use same and next day mitigation (i.e. Gas Deliveries) for 656 MMcFs/day	Mitigate	Operational reliability	Financial	5	4			Asset Management Recommends the following Risk Treatment: 1.Accept Risk from now until Winter 22/23 2.Treat Risk in Winter 2022-23 with Operational Change 3.Forecast timing when Dehy exceeds capacity •Identify long term risk treatment alternatives as part of W2023+ asset plans •Incremental Dehydration Capability •Incremental Wet Transmission HP •Installation of Single Stage F-Plant Wheels (regular configuration) •Decrease By-Pass	Paul Norris	2023		Operational Impact: L2 C5 Reputational: L1 C1	MP-05: Integrity	2023-01-31
1. Natural gas distribution	3.1 Fleet		1. Ontario Distribution		1.10.1. EGI Aggregate										EGI	FINAL	474	[redacted]	Steve McGivery	[redacted]					1) Detect 2) Prevent 3) Prevent	Terrorism & asset security	Financial	4	2						[redacted]		MP-06: Security	10/31/2022
1. Natural gas distribution	3.1 Fleet		1. Ontario Distribution		1.10.1. EGI Aggregate										EGI	FINAL	475		Steve McGivery						1) Prevent 2) Prevent	Terrorism & asset security	Financial	2	3							Reputation: L1 C2 Low	MP-06: Security	10/31/2022
1. Natural gas distribution	3.1 Fleet		1. Ontario Distribution		1.10.1. EGI Aggregate										EGI	FINAL	476		Steve McGivery						1) Prevent 2) Prevent 3) Prevent	Cyber security	Reputational	1	4							Financial:L4 C1 Low Operational: L1 C1 Low	MP-06: Security	10/31/2022

First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version	Current ID
1. Natural gas distribution	1.4. Office	1.4.1. Field office	1. Ontario Distribution	1.3. GTA West & Niagara (Areas 20, 50, & 80)	1.3.1. 20 – Mississauga										EGI	FINAL	477
1. Natural gas distribution	1.4. Office	1.4.1. Field office	1. Ontario Distribution	1.7. Southeast (Waterloo/Brantford, Halton/Hamilton)	1.7.4. Div_16 - Hamilton									N/A	LUG	FINAL	483
1. Natural gas distribution	1.4. Office	1.4.1. Field office	1. Ontario Distribution	1.7. Southeast (Waterloo/Brantford, Halton/Hamilton)	1.7.4. Div_16 - Hamilton									N/A	LUG	FINAL	484
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										96	LGD	FINAL	485
1. Natural gas distribution			1. Ontario Distribution											97	LGD	FINAL	486
1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution											98	LGD	FINAL	487
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										99	LGD	FINAL	488
1. Natural gas distribution			1. Ontario Distribution											100	LGD	FINAL	489
1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution											101	LGD	FINAL	490
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										102	LGD	FINAL	491
1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution											103	LGD	FINAL	492
1. Natural gas distribution			1. Ontario Distribution											104	LGD	FINAL	493
1. Natural gas distribution	1.5. Aggregate	1.5.1. All Distribution Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										105	LGD	FINAL	494
1. Natural gas distribution			1. Ontario Distribution											106	LUG	FINAL	495
1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution	1.5. GTA East (Areas 30 & 40)										N/A	EGI	FINAL	496
1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution	1.5. GTA East (Areas 30 & 40)										N/A	EGI	FINAL	497
3. Aggregate	2.1. Station	1.2.1. Customer Station	1. Ontario Distribution	1.5. GTA East (Areas 30 & 40)	1.9.1. Aggregate									N/A	EGI	FINAL	498
1. Natural gas distribution	2.6. Aggregate	2.3.3. Pipeline Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.10.1. EGI Aggregate									2	EGI	FINAL	499
1. Natural gas distribution	2.6. Aggregate	2.3.3. Pipeline Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.10.1. EGI Aggregate									18	EGI	FINAL	500
3. Aggregate			3. Aggregate											109	EGI	FINAL	501
1. Natural gas distribution	2.6. Aggregate	2.3.3. Pipeline Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.10.1. EGI Aggregate									111	EGI	FINAL	502
3. Aggregate			3. Aggregate											53	EGI	FINAL	503
3. Aggregate			3. Aggregate											54	EGI	FINAL	504
1. Natural gas distribution	2.6. Aggregate	2.3.3. Pipeline Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.10.1. EGI Aggregate									55	EGI	FINAL	505
1. Natural gas distribution	2.6. Aggregate	2.3.3. Pipeline Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.10.1. EGI Aggregate									56	EGI	FINAL	506
2. Pipeline transportation of natural gas	2.6. Aggregate	2.3.3. Pipeline Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.10.1. EGI Aggregate									57	EGI	FINAL	507
3. Aggregate			3. Aggregate											109	EGI	FINAL	508

Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard	Source	Consequences
477	[redacted]	Mark Maxwell	[redacted]	[redacted]	[redacted]	[redacted]
483	Strathearne Contaminated Site Management (Non MECP Order) - Other contaminants (Likely Case)	Jennifer Burnham	Potential for contaminants (other than PCBs identified in MECP order) from neighboring site move to company site leading to localized impact	Contaminated Soil and Water	Other contaminants (such as PCB,cis-1,2-Dichloroethylene around 300K ug/L, Vinyl chloride 4100 ug/L, Total PCBs 51.9 ug/L, 1,1,2-Trichloroethane 246 ug/L, trans-1,2-Dichloroethylene 2200 ug/L) at the site due to historical neighboring site's operation	Contaminants from neighboring site coming on the company site and remaining on the site with high concentrations **NOTE for consequence rankings:** E: Contaminants currently on site based on latest information H&S : Based on exposure to workers when they work at an underground station
484	Strathearne Contaminated Site Management (Non MECP Order) - Other contaminants (Worst Credible Case)	Jennifer Burnham	Potential for contaminants (other than PCBs related to MECP order) from neighboring site move to company site and then move offsite which could impact public.	Contaminated Soil and Water	Other contaminants (such as PCB,cis-1,2-Dichloroethylene around 300K ug/L, Vinyl chloride 4100 ug/L, Total PCBs 51.9 ug/L, 1,1,2-Trichloroethane 246 ug/L, trans-1,2-Dichloroethylene 2200 ug/L) at the site due to historical neighboring site's operation	Contaminants from neighboring site coming on the company site and moving off site (most likely move with ground water or with vapour at subsurface) at concentration exceeding exposure limits **NOTE for both likelihood and consequence rankings:** E: Based on area of coverage and haven't confirmed pathways on how contaminants would move off site, hence there is higher uncertainty on likelihood ranking. H&S (Worker): Same as risk ID 483 H&S (Public): More credible case is contaminated vapour getting into someone's house R (H&S): Based on regulator could write an order R (E): Based on regulatory engagement F (Clean up cost & fines): Cost to investigate and clean up cost (as it is off site, could put a barrier to stop contaminants moving off site) Evaluate worst credible case
485	[redacted]	Steve McGivery	[redacted]	[redacted]	[redacted]	[redacted]
486	[redacted]	Steve McGivery	[redacted]	[redacted]	[redacted]	[redacted]
487	[redacted]	Murray Costello	[redacted]	[redacted]	[redacted]	[redacted]
488	[redacted]	Steve McGivery	[redacted]	[redacted]	[redacted]	[redacted]
489	[redacted]	Steve McGivery	[redacted]	[redacted]	[redacted]	[redacted]
490	[redacted]	Murray Costello	[redacted]	[redacted]	[redacted]	[redacted]
491	[redacted]	Steve McGivery	[redacted]	[redacted]	[redacted]	[redacted]
492	[redacted]	Murray Costello	[redacted]	[redacted]	[redacted]	[redacted]
493	[redacted]	Steve McGivery	[redacted]	[redacted]	[redacted]	[redacted]
494	[redacted]	Steve McGivery	[redacted]	[redacted]	[redacted]	[redacted]
495	[redacted]	Steve McGivery	[redacted]	[redacted]	[redacted]	[redacted]
496	Bowmanville Gate Station - Vehicle accident collision with station	Steve McGivery	Vehicle accident collision with station impacting gas carrying asset and ability to deliver gas to downstream customers.	3rd party damage	1. Accidental vehicle collision with station asset at highway speeds (posted speed limit on Hwy 115 is 90 kph). Traffic volume on Hwy 115 has increased since recent addition of on/off ramps connecting it to Hwy 407. Station is located just past a bend in the highway which may impact chance of vehicle accident. Station is slightly below road level. Highway is in rural area that may be poorly lit during nighttime driving or have wildlife hazards.	1. Possible vehicle impact with outlet valve and/or bypass valve leading to inability to isolate station concurrently when the station is leaking due to vehicle collision. Make safe isolation at TC Energy site or isolation point downstream of station during winter may result in 61,000 customers without gas service during a design day.
497	Bowmanville Gate Station - Vehicle collision with on site workers	Steve McGivery	Public vehicle collision with workers present at Bowmanville Gate Station for routine or planned work	Employee injury during response	New technology asset operations creating noise level above allowable limits (RNG, Hydrogen Assets and any new initiatives under development)	Possible vehicle impact with worker present at station. Resulting in possible fatality
498	Bowmanville Gate Station - Vehicle collision with odourant delivery truck	Steve McGivery	Public vehicle collision with odourant delivery truck at Bowmanville Gate Station causing potential odourant leak that could result in nuisance odourant calls	Accidental release noxious material i.e. odourant		Potential collision involving an odourant delivery truck may cause an odourant leak resulting in mass nuisance odourant calls impacting a significant distance downwind from the initial spill. nuisance calls require operations response and public evacuations to confirm situation is safe, reputation risk
499	Noise impact offsite to public from pipeline operation from GDS Assets and New Technologies	Jennifer Burnham	Pipeline operation activities and New technology asset operations causing noise level above allowable limits impacting public offsite	Elevated noise from operating GDS Assets	Pipeline operation activities creating noise level above allowable limits (e.g., Gate stations, compressor stations, pipelines, etc.) New technology asset operations creating noise level above allowable limits (RNG, Hydrogen Assets and any new initiatives under development)	Causing media and regulatory impacts and residential complaints NOTE: Evaluated based on media coverage and regulatory impact, both are grouped into reputational per current matrix.
500	Improper management of contaminated soil and water during sub-surface employee activities	Jennifer Burnham	Improper management of contaminated soil and water during sub-surface employee activities	Contaminated Soil and Water	Unable to identify contaminated soil and water	Improper management or disposal of contaminated soils / water causing misplacement of contaminates exposing public to harm and regulatory impacts NOTE: H&S : Impact to public due to exposure to contaminated soils / water Reputation: Regulatory impact
501	Improper identification, storage and disposal of hazardous waste	Jennifer Burnham	Improper dentification, storage and disposal of hazardous waste (example: batteries, NORM, aerosols, gas cylinders, chemicals, PCBs, pyrophoric filters, mercury, etc.)	Generation And Disposal Of Waste (Hazardous and Non-Hazardous) / Generation And Disposal Of NORM	Improper identification, storage and disposal of hazardous waste	Release of hazardous waste to the environment, leading to contamination of soils / water, causing exposure to public and / or regulatory impacts NOTE: H&S : Based on a scenario where someone handling is the waste could be exposed to hazardous material
502	Improper treatment / management of water (withdraw / diversion and discharge)	Jennifer Burnham	Improper water treatment/management prior during withdraw / diversion and disposal of water	Erosion and Sedimentation	Discharge : Improper release of water from storm ponds and, excavation dewatering, abandoned main water, hydrostatic test water Withdraw / diversion : Fail to relocate aquatic species before withdraw / diversion of water	Discharge : Release of poor quality water to the environment and sedimentation / erosion (Impacting water ways) Withdraw / diversion : Impact aquatic species NOTE: Discharge - Environmental : Based on potential sedimentation / erosion, what would be the area of impact. Withdraw / diversion : Impact species (legacy UG Sudbury Project)
503	Air Emissions - release of combustion by-products	Jennifer Burnham	Release of combustion by products to the environment through natural gas fired equipment / compressor engines / fleet and construction vehicles/emergency generators / gate stations / buildings / dehydrators / incinerators. Risk of air emission exceedances from these activities.	Emissions - product of combustion	Abnormal operation of heating systems using natural gas fired equipment, compressor engines and fleet and construction vehicles, emergency generators, gate stations, buildings, dehydrators, incinerators	Release combustion by products to the environment potential to exceed air emission permit (it is based on the air emission concentration at the property line) NOTE: Reputation - based on compliance issue Environment - low ranking as it is typically air emission from emergency generator, boiler, and furnaces
504	Air Emissions - Fail to report unplanned releases of natural gas causing adverse effects leading to regulatory impact	Jennifer Burnham	Releases of natural gas that are outside of day-to-day operational activities, not part of the normal operation of the natural gas system and/or that cause an adverse effect	Spills of pollutant into the natural environment (includes solid, gas and liquid pollutants, refrigerants, pcbs)	Releases of natural gas that are outside of day-to-day operational activities, not part of the normal operation of the natural gas system and/or that cause an adverse effect	Potential failure to report release of natural gas causing adverse effects to the minister (Regulatory impact)
505	Inadvertent release of bentonite to natural environment causing adverse effect during pipeline drilling	Jennifer Burnham	Inadvertent release of bentonite to natural environment causing adverse effect during pipeline drilling (horizontal directional drilling) using bentonite which could contaminate the environment.	Spills of pollutant into the natural environment (includes solid, gas and liquid pollutants, refrigerants, pcbs)	Use of bentonite in pipeline drilling (Horizontal Directional Drilling)	Release of bentonite to the natural environment causing adverse effect and impacting sensitive environmental receptors NOTE : Environmental Impact is based on the size (area) being impacted. Used Sturgeon lake incident as guidance to rank this risk
506	Release of odourant causing adverse effects (Odourant Spill)	Jennifer Burnham	Release of odorant to the environment during odourant handling (transfers and deliveries), equipment malfunction (leaky gaskets, seals, corrosion on tank or valves) and commissioning/decommissioning actives. Worker could be exposed to odorant. It would also trigger emergency calls from area where odorant is dispersed, leading to unnecessary emergency responses from workforce and create concern with customers.	Spills of pollutant into the natural environment (includes solid, gas and liquid pollutants, refrigerants, pcbs)	Equipment failure e.g. leakage at storage tank Human error e.g. Overfilling storage tank Vapour release e.g. loose fittings, failed equipment	Release of odorant to the natural environment causing adverse effects NOTE : Reputational - based on causing disruption or inconvenience to public. Based on the Ottawa incident (other examples include Sault Saint-Marie, Coburg) Environmental - based on the effect to clean up the spill.
507	Release from bulk liquids and hazardous materials (i.e. crude oil, glycol, brine, diesel, oils, gasoline, pipeline liquids, LNG, etc.) causing adverse effects	Jennifer Burnham	Release from bulk liquids and hazardous materials (i.e. crude oil, glycol, brine, diesel, oils, gasoline, pipeline liquids, LNG, etc.) causing adverse effects	Spills of pollutant into the natural environment (includes solid, gas and liquid pollutants, refrigerants, pcbs)	Equipment failure e.g. leakage at storage tank Human error e.g. Overfilling storage tank Loss of primary containment	Spill of bulk liquids and hazardous materials (i.e. brine, crude oil, glycol, pipeline, liquids, LNG, diesel, oils, gasoline, etc.) to the natural environment causing adverse effects NOTE: Environmental Impact : based on potential spill in a river i.e. Detroit river crossing. This is considered a worst creditable case
508	Improper waste management (Hazardous and non-hazardous waste)	Jennifer Burnham	Improper waste management (Hazardous and non-hazardous waste) leading to rogatory impact (Reg. 347) (non-hazardous example: batteries, NORM; hazardous waste examples: aerosols, gas cylinders, chemicals, PCBs, pyrophoric filters, mercury, etc.)	Generation And Disposal Of Waste (Hazardous and Non-Hazardous) / Generation And Disposal Of NORM	Not following procedures in managing waste	Fines/orders, regulatory non-compliance from not complying with Reg. 347

Current ID	Controls	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region
477	[redacted]	1) Detect / Mitigate 2) Detect / Mitigate 3) Prevent 4) Detect / Mitigate	Terrorism & asset security	Operational	3	5		
483	- E-PRO-111-Suspect Soils Management Program (Protect workers if they were to show up at the site) - E-PRO-104-Hazardous Waste Management Program (Same as above) - Contaminated Sites Working Group (This would help to formulate plan on dealing with the contamination - right now no action has been taken other than dealing with the contaminates that moved offsite.) - Station is in a concrete box (The chances that workers could be exposed to contaminants would be low (effective for employee H&S risk) - Site investigation has been completed in the past 20 yrs.	Detect/Mitigate Mitigate Detect Prevent Detect	Environmental	Environmental	7	2		
484	- E-PRO-111-Suspect Soils Management Program (Protect workers if they were to show up at the site) - E-PRO-104-Hazardous Waste Management Program (Same as above) - Contaminated Sites Working Group (This would help to formulate plan on dealing with the contamination - right now no action has been taken other than dealing with the contaminates that moved offsite.) - Station is in a concrete box (The chances that workers could be exposed to contaminants would be low (effective for employee H&S risk) - Site investigation has been completed in the past 20 yrs. - Stormsewer was decommissioned to limit pathways of contaminants moving offsite	Detect/Mitigate Mitigate Detect Prevent Detect Prevent	Environmental	Environmental	5	4		
485	[redacted]	Mitigate Prevent Detect Detect, Mitigate Mitigate Detect , Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Operational	3	2		
486	[redacted]	Mitigate Detect, Mitigate Prevent	Terrorism & asset security	Operational	3	2		
487	[redacted]	Mitigate Prevent Detect Detect, Mitigate Mitigate Detect , Mitigate Mitigate Mitigate	Terrorism & asset security	Operational	2	7		
488	[redacted]	Mitigate Prevent Detect Detect Mitigate Detect, Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Operational	6	2		
489	[redacted]	Mitigate Prevent Detect Mitigate	Terrorism & asset security	Health & Safety	2	3		
490	[redacted]	Mitigate Prevent Detect Detect Mitigate Detect, Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Operational	2	7		
491	[redacted]	Mitigate Prevent Detect Mitigate Detect, Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Financial	6	1		
492	[redacted]	Mitigate Prevent Detect Mitigate Detect, Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Operational	2	7		
493	[redacted]	Mitigate Prevent	Terrorism & asset security	Financial	6	1		
494	[redacted]	Mitigate Prevent Detect Mitigate Mitigate Detect, Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Reputational	4	4		
495	[redacted]	Mitigate Prevent Mitigate Mitigate	Terrorism & asset security	Reputational	3	3		
496	1. Emergency response procedures 2. Jersey barriers currently in front of station. Jersey barriers are not recommended by MTO due to potential concerns with driver safety regarding head on collisions with side of jersey barrier 3. Station is located inside a fence however a fence may not protect gas carrying assets during a collision at highway speeds 4. Station is set back somewhat from highway shoulder but may not be enough distance 5. Station bypass and outlet valve available. Valves may be concurrently impacted by a vehicle accident as they are both located closest to the road on site 6. Ability to isolate using TC Energy valve or downstream isolation point to make safe. Isolation may result in customer losses depending on time of year (System back feeding available during spring, summer, and fall according to QRA template)	Mitigate Prevent, Mitigate Mitigate Prevent, Mitigate Mitigate Mitigate	Operational reliability	Operational	2	7		
497	1. Traffic management plan for major construction activities and odourant deliveries 2. Emergency response procedures 3. Jersey barriers currently in front of station are not recommended by MTO due to potential concerns with driver safety 4. Station is located inside a fence but may not protect gas carrying assets during a collision 5. Station is separated somewhat from highway but may not be enough distance	Prevent Mitigate Mitigate Mitigate Prevent, Mitigate	Operational reliability	Health & Safety	2	5		
498	1. Traffic management plan for major construction activities and odourant deliveries 2. Odourant spill kits available on site 3. Emergency response procedures 4. Station is separated somewhat from highway but may not be enough distance	Prevent, Detect, Mitigate Mitigate Mitigate Prevent	Operational reliability	Reputational	1	6		
499	- Environmental Compliance Approvals (ECA)/Environmental Activity and Sector Registry (EASR) - permit procedure which needs to demonstrate operations meet requirement, if not, it requires controls to be in place. - Engineering design such as physical barriers (e.g., berms, walls) - Noise Modeling exercises - EHS Manual Section 20.1 - Environment Compliance Approval - EPRO 112 - Environment Compliance Approval Management - Environment Compliance Approval Training - Complaints log - Operation/Maintenance Manuals - TSSA, ESA Field Approvals	Prevent, Detect, Mitigate Mitigate Prevent, Mitigate Prevent, Mitigate Prevent, Mitigate Prevent, Mitigate	Environmental	Reputational	3	3		
500	- EHS Manual Section 11.08 - Suspect Soils (LUG) - EPRO 111 - Suspect soils procedure (LGD) - Online training on suspect soils - Suspect soils notes in GIS / List of suspect soil sites	Prevent Prevent Prevent, Detect Prevent, Detect	Environmental	Reputational	2	3		
501	**LEG:** E-PRO-107 Spill Management E-PRO-104 Hazardous Waste Management **LUG:** • EHS Manual Section 14 - Waste Management (NORM Consideration); • EHS Manual Section 11 "Hazardous Materials -Pipeline Contaminants - Handling Storage, and Disposal • EHS Manual Section 11.7.8, "Pipeline Coatings - Handling, Storage and Disposal;" • EHS Manual Section 14 - Waste Management • EHS Manual Section 11.05 - Compressed Gas • EHS Manual Section 12 - Spill Response Recycling requirement; general waste; Waste Audit; EHS Manual Section 14 - Waste Management (CFL and battery recycling programs) EHS Manual Section 11.14 - Mercury Management: Includes Standard, Procedures, Processes, training, site inventory, and reference documents; on-site signage; Mercury remediation program in place	Prevent, Detect, Mitigate Prevent, Detect Prevent, Detect Prevent, Detect Prevent, Detect Prevent, Detect Prevent, Detect Prevent, Detect, Mitigate Prevent, Detect	Environmental	Reputational	3	3		
502	**LEG and LUG:** ECA (Environmental Compliance Approval) Engineering designs Monitoring and sampling programs Spill contingency plans and training Permits to Take Water (PTTW) Environmental Activity Sector Registry (EASR) for Water Taking Environmental Protection Plans (EPP) Conservation Authority Permit **LEG:** E-PRO-104 Hazardous Waste Management Program E-PRO-17 Spill Management C&M Manual LUG: [Controls ?]	Prevent Prevent Prevent, Detect Mitigate Prevent Prevent Prevent, Detect, Mitigate Prevent Prevent, Detect Mitigate Prevent, Mitigate	Environmental	Environmental	3	6		
503	**LUG Controls:** - 3973-BD5N7U Environmental Compliance Approval (ECA) - Permit from MoE - EHS Manual : Section 20 Environmental Compliance Approval procedure **LEGD Controls:** - E-PRO-112-ECA management procedure - PW-ECA 7841-9ECKVY (Province Wide Environmental Compliance Approval) - Permit from MoE - E-PRO-101-Air Emissions Reporting **Combined Company Controls:** - Annual Asset Management Station Review with Environment (review AM plan for stations to ensure no exceedance before plan being executed) - Engineering controls (e.g. scrubbers, stacks)	Prevent, Detect, Mitigate Prevent, Detect, Mitigate Prevent, Detect, Mitigate Prevent, Detect, Mitigate Detect, Mitigate Prevent, Detect, Mitigate Prevent, Mitigate	Operational regulation	Reputational	3	2		
504	- LEGD E-PRO-107 Spill Management - LUG EHS Manual Section 12 - Spill Response - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan) - Incident investigation - Environmental Incident Guide - Spill action center reporting for 3rd party damages (C&M Chapter 32) - Ontario 1 Call / Damage Prevention Program to prevent 3rd party damages - Damage Prevention Field Support - Construction and Maintenance Manual Section 8.19 (Preventative Surveillance)	Mitigate Mitigate Detect, Mitigate Mitigate Mitigate Mitigate Prevent Prevent Prevent	Operational regulation	Reputational	7	2		
505	E-PRO-107-Spill and Release Management Program EHS Manual - Section 12 Spill Management EPP (Environmental Protection Plan)- project specific Environmental Permits E-PRO-104-Hazardous Waste Management Program EHS Section 14 Waste Management Construction and Maintenance Manuals EM (Emergency Management) exercises Horizontal Directional Drilling Contingency plans DFO (Fisheries Ocean Canada) Agreement LUG Stream Crossing Review (permitting)	Prevent / Detect / Mitigate Prevent / Detect/Mitigate Prevent / Detect/Mitigate Prevent/ Detect / Mitigate Mitigate Mitigate Mitigate Prevent/Detect/ Mitigate Mitigate Prevent / Detect/ Mitigate Prevent / Detect / Mitigate Prevent / Detect / Mitigate	Environmental	Environmental	6	3		
506	E-PRO-104-Hazardous Waste Management Program EHS Manual - Section 12 Spill Management E-PRO-107-Spill and Release Management Program EHS Section 14 Waste Management MSEM (Measurement Station Equipment Manual) Network Operations Manual EM (Emergency Management) exercises Emergency Response Plan (ERP)	Mitigate Prevent / Mitigate Prevent /Mitigate Mitigate Prevent / Detect / Mitigate Prevent / Detect / Mitigate Mitigate Mitigate	Environmental	Reputational	5	3		
507	**LEG:** E-PRO-104-Hazardous Waste Management Program E-PRO-107-Spill and Release Management Program Operational Procedures for Liquid Storage Facilities **LUG:** EHS Manual Section 12 - Spills; EHS Manual Section 15 - TDG (Transportation of Dangerous Goods); EHS Manual Section 14 - Waste Management; Storage tank Inventory **Integrated company** Engineering design (e.g. Secondary containment, berms, High level alarms on storage tanks, Floor coating in buildings) MP Manuals EM (Emergency Management) exercises Contingency plans Emergency Response Plan (ERP) Operations and Maintenance activities	Mitigate Prevent / Mitigate Prevent / Detect / Mitigate Prevent / Mitigate Mitigate Mitigate Detect Prevent / Detect Detect / Mitigate Mitigate Mitigate Mitigate	Environmental	Environmental	3	6		
508	**LEG:** E-PRO-104 Hazardous Waste Management C&M Manual Section 4.0 **LUG:** • EHS Manual Section 14 - Waste Management • EHS Manual Section 11 **Integrated Company** Hazardous waste management training Signages and sorting bins at facilities to support proper handling of waste	Prevent / Detect / Mitigate Prevent / Detect / Mitigate Prevent / Detect / Mitigate Prevent / Detect / Mitigate Prevent Prevent	Environmental	Reputational	5	3		

Current ID	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
477				[redacted]	[redacted]	MP-06: Security	10/31/2022
483	Implement continuous monitoring program at the site (Timing and strategy yet to be determined as it requires discussion with legal to determine when the company could take action)	Erin Nolan	Q4 2023	Timeline changed from Q4 2022 to Q4 2023. Management program goal for 2023 is to work on a contamination site plan - 5/2/2023	H&S (E): C1, L5, Low NOTE: There is no change to expected residual risks as the current risk treatment plan is to monitor on site contaminants. The potential risk for contaminants moving offsite is evaluated in Risk ID 484.	MP-03: Environmental	5/2/2023
484	Implement continuous monitoring program at the site (Timing and strategy yet to be determined as it requires discussion with legal to determine when the company could take action)	Erin Nolan	Q4, 2023	Timeline changed from Q4 2022 to Q4 2023. Management program goal for 2023 is to work on a contamination site plan - 5/2/2023	R (related to environmental impact): C3, L5, Med H&S (E): C1, L5, Low H&S (P): C3, L4, Med R (related to public H&S): C3, L4, Med F : C3, L5, Med	MP-03: Environmental	5/2/2023
485					One RR only	MP-06: Security	7/4/2022
486					One RR only	MP-06: Security	7/4/2022
487					One RR only	MP-06: Security	2021-06-11
488					H&S, C3, L2, Low Reputation C3, L2, Low	MP-06: Security	7/4/2022
489					Reputation C3, L2 Low	MP-06: Security	7/4/2022
490					H&S, C3, L2, Low Reputation C3, L2, Low	MP-06: Security	2021-06-11
491					Operational C2, L4, Low	MP-06: Security	7/4/2022
492					One RR only	MP-06: Security	2021-06-11
493					One RR only	MP-06: Security	7/4/2022
494					Operational C2, L4, Low	MP-06: Security	7/4/2022
495					One RR only	MP-06: Security	7/4/2022
496					Operational: Medium, L1 C7	MP-01: Asset	2021-06-28
497					Worker H&S: Low, L1 C5	MP-01: Asset	2021-06-28
498					Reputation: Medium, C6 L1	MP-01: Asset	2021-06-28
499				Made changes to the Title, Description, Source and Controls (10/6/2022)		MP-03: Environmental	2022-10-06
500					H&S : L2C3 Low	MP-03: Environmental	4/26/2021
501					H&S : L2C3 Low	MP-03: Environmental	4/26/2021
502					Discharge - Based on potential sedimentation / erosion, Environmental : Based on area of impact. L3C3, Low Reputation : L3C2, Low (regulatory impact) Withdraw / diversion : Impact species (legacy UG Sudbury Project) Environmental : L3C6, Med Reputation (regulatory impact): L3C4, Med Financial : L3C2, Med	MP-03: Environmental	4/26/2021
503						MP-03: Environmental	4/26/2021
504						MP-03: Environmental	2021-06-24
505						MP-03: Environmental	4/26/2021
506				November 10, 2021 - Minor Spelling Changes 23/03/2023 AMH - Updated controls per Dale Smith	Operational: L3 C4 Med (Based on LUG and LGD rankings) Environmental L4 C3 Med (same as Environmental Program's rankings)	MP-03: Environmental	2022-06-13
507	STO Missing relief tank mitigation plan **Current Status** Relief tank - for the Dawn tanks 4 are installed and 2 are awaiting installation. The two remaining tanks are on-site and the piping is fabricated we just have to tie them in.	Jeff Falkiner	End of 2021	November 10, 2021 - Minor Spelling Changes Treatment plan complete - 5/2/2023	Reputational (under Regulatory) : L3 C5 Medium	MP-03: Environmental	5/2/2023
508					One RR only	MP-03: Environmental	4/26/2021

First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version	Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard	Source	Consequences	Controls	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
1. Natural gas distribution	2.6. Aggregate	2.3.3. Pipeline Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.10.1. EGI Aggregate									1	LUG	FINAL	509	Air Emissions - release of natural gas leading to greenhouse gas emissions	Jennifer Burnham	Release of natural gas through operation of gas distribution system (i.e. compressor stations, blow downs, purging, line breaks, pressure relief valves, leaks, etc.), leading to green house gas emissions	Emissions - green house gases (including natural gas)	1. Venting of natural gas due to normal operation (e.g. venting, purging) 2. Damages by 3rd party, fugitive losses due to leaks	Air emission to environment, contributing to climate change and potential regulatory impact (such as green house regulation to report GHG, methane regulation for STO) NOTE: Reputational - Based on climate change, based on a noticeable and sizable releases (could be planned or unplanned releases) Reputational (rel. to regulatory impact) - Based on methane regulation, more regulatory requirements starting in 2020 Environmental impact is not ranked here as the consequence rating description is not applicable for green house gas emission.	-Spills reporting procedures -Leak Survey -Engineering design -Ontario 1 Call -LEGD E-PRO-107 Spill Management -LUG EHS Manual Section 12- Spill Response - Methane regulation program (specific for STO, infrared detection of leaks and repair) - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and ERP (Emergency Response Plan) -Work Permit -Incident Investigation - Damage Prevention Field Support - Construction and Maintenance Manual Section 8.19 (Preventative Surveillance) - MP-07 Damage Prevention Programs - MP-05 Integrity Management / MP-01 Asset Management	Mitigate Detect Prevent, Mitigate Prevent Prevent, Mitigate Mitigate Detect, Mitigate Mitigate Prevent Prevent Mitigate Prevent Prevent/Detect/Mitigate Prevent/Detect/Mitigat	Environmental	Reputational	5	3			Implement corporate green house gas emissions targets and emission reduction strategy (Timeline is based on developing ways to track targets and implementing reduction opportunities) (Lead by Env. Tech. Manager with operations implementing the change)	Peter Mussio	2021		Reputational impact - L4 C3 Medium	MP-03: Environmental	2021-05-03
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.4. Toronto (Area 10)										New 2021	EGI	FINAL	511	Large Isolation Areas	Neil MacNeil	Potential 3rd party damage, integrity issue, or natural disaster event causing a significant loss of containment event requiring an emergency isolation strategy to be enacted for a large section of the distribution network	Accidental release/LOC flammable gas	Potential 3rd party damage, integrity issue, or natural disaster causing a significant loss of containment	Loss of containment event with the potential for migration to sewer system connected to customer premises and indoor ignition where there is potential threat to life. Public safety impact to multiple premises in area where operations cannot reasonably determine a smaller isolation area such as a street. Timely emergency response could be impacted by cold winter causing large frost cap preventing hydrovac to create isolation point	1. Damage prevention 2. Integrity management program 3. Current network design would require multiple digs and squeeze locations to isolate 4. Gas is odourised for leak detection 5. Emergency response procedures	Mitigate Mitigate Prevent Detect Mitigate	Operational reliability	Health & Safety	2	7							Operational: Medium L3 C6 Reputational: Medium L2 C6 Reputational: Medium L3 C6 H&S: Medium L2 C7 Operational: High L3 C7 Reputational: Medium L3 C6 H&S: Medium L2 C7 Operational: Medium L3 C6 H&S: Medium L2 C5	MP-01: Asset	7/4/2022
1. Natural gas distribution	1.1. Pipe	1.1.1. Distribution Main	1. Ontario Distribution	1.1. Northern (Union Eastern, Northwest, & Northeast Districts)										New 2021	EGI	FINAL	512	English River (Atikokan) Lateral	Nicole Lehto	Potential corrosion leaks due to pipeline coating damaged by abrasive rocks during installation Possible overground flooding from surface water collection in abandoned mines / MNRF controlled outflow from dams	Corrosion external	Pipeline was installed by dragging pipe over rocky area into place in a swampy area. Abrasive rocks potentially damaged coating leading to corrosion Over ground flooding due to surface water collection in abandoned mines over long term and MNRF controlled outflow from dams (planned outflow to mitigate poor water chemistry due to ground contamination of abandoned mining operations in area)	Corrosion leaks to date have been small but due to the pressure in the pipe and gas escaping, leaks grow faster than a general corrosion problem. Leaks have historically occurred in remote areas called in by public (camping or hunting), low chance of ignition in remote areas. Due to remote location, limited workforce, and single feed to Atikokan leak repairs are more costly. 2 hour drive to respond to repairs. Over ground flooding may cause bank erosion or washout exposing pipe segment along northern edge, just east of Steep Rock Lake. Flooding may lead to potential accessibility issues which could impact future inspections / potential emergency response. Risk ranking for leak response and repair to a corrosion leak in an area that has flooded. Historically that area at risk of flooding has not had a history of corrosion or clamp repairs.	1. Procedures to bypass to make repairs 2. Corrosion Protection 3. Coating 4. Leak survey 5. Gas odourised for leak detection 6. Emergency response procedures	Mitigate Mitigate Mitigate Detect Detect Mitigate	Operational reliability	Operational	6	3				Fred Butrico		Treatment plan and proposed timeline discussion in progress by Kuladeep Mummidisetty	Financial: Medium L6 C3 (Corrosion Hazard) Operational: Medium L4 C3 (Weather & Outside Forces) H&S: Low L1 C3 (Weather & Outside Forces) Financial: Medium L6 C2 (Weather & Outside Forces) Environmental: Medium L4 C3 (Weather & Outside Forces)	MP-05: Integrity	7/7/2022
1. Natural gas distribution	1.1. Pipe	1.1.1. Distribution Main	1. Ontario Distribution	1.14. EGI Aggregate										New 2021	EGI	FINAL	513	Legacy pin offs abandoned in service - weld failure	Fred Butrico	Failure of welds at legacy pin offs abandoned in service causing leaks.	Weld Failure	Potential variation in welding practices, different metal properties including hard spots that may be prone to cyclic failure by cracking	Potential leaks from a slow growing/stable crack along the edge of a hard spot located at the main	Leak detection Program Gas is odorized Pressure limitation in IP system P<64psi (440kPa) Abandonment Procedure (service line is caped) Bypass procedure to limit affected customers during repair	Detect Detect	Operational reliability	Financial	2	2							Operational C2 L2	MP-05: Integrity	6/25/2021
1. Natural gas distribution	1.1. Pipe	1.1.1. Distribution Main	1. Ontario Distribution	1.14. EGI Aggregate										New 2021	EGI	FINAL	514	Legacy pin offs abandoned in service - coating failure	Fred Butrico	Failure of the coating at the legacy pin off locations abandoned in service, causing corrosion and subsequently leaks.	Corrosion external	Potential coating deficiencies leading to corrosion	Potential leak from a pin hole located at the main	Coating policy and Coating Selection Coating Applicator training Cathodic Protection Leak detection Program Gas is odorized Pressure limitation in IP system P<64psi (440kPa) Abandonment Procedure (service line is caped) Bypass procedure to limit affected customers during repair	Mitigate Mitigate Mitigate Detect Detect Mitigate Mitigate Mitigate	Operational reliability	Financial	2	2							Operational C2 L2	MP-05: Integrity	6/25/2021
2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation	1.8. Storage	1.8.3. 70 – Storage									New 2021	EGI	FINAL	515	Corunna Compressor Station – rare worker safety event due to loss of containment	Wes Armstrong	Corunna Compressor Station – rare worker safety event due to loss of containment	Accidental release/LOC flammable gas	Leaks from site equipment	Leading to release of flammable gas and potential for fire / explosion	Changes already made to operators' rounds (to reduce time spent in compressor buildings)	Prevent Detect	Workforce safety	Health & Safety	N/A	N/A	N/A	Intolerable Region	**Short-term Risk Treatment Plan Q1 2022** -Operations to lead on investigating potential operational adjustments (in place) -Changes already made to operators' rounds (to reduce time spent in compressor buildings) -Plan in progress for further proposed changes (depressurizing units for longer term outages, reducing time with units pressurized) -Quarterly Corunna compressor usage tracking ongoing **Long-term Risk Treatment Plan Q1 2022** -20 km NPS 36 (TR7) pipeline approved by Capital Allocation Committee (CAC). LTC application approved by OEB November 3, 2022 for ISD of 2023.	**Short-term Risk Treatment Plan :** Tarik Kasem **Long-term Risk Treatment Plan :** Mohamed Soliman	2023 (Long-Term)	Risk Results based on individual risk criteria. Updated treatment plan and treatment owner (1/31/2023).		MP-01: Asset	1/31/2023
2. Pipeline transportation of natural gas	3.1 Fleet	2.4.5. Transportation Aggregate	2. Ontario Transportation	1.14. EGI Aggregate											EGI	FINAL	516	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1) Detect 2) Prevent 3) Prevent	Terrorism & asset security	Financial	4	2						[redacted]		MP-06: Security	10/31/2022
2. Pipeline transportation of natural gas	3.1 Fleet	2.4.5. Transportation Aggregate	2. Ontario Transportation	1.14. EGI Aggregate											EGI	FINAL	517	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1) Prevent 2) Prevent	Terrorism & asset security	Financial	2	3						[redacted]	Reputation: L1 C2 Low	MP-06: Security	10/31/2022
2. Pipeline transportation of natural gas	3.1 Fleet		2. Ontario Transportation												EGI	FINAL	518	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1) Prevent 2) Prevent 3) Prevent	Cyber security	Reputational	1	4						[redacted]	Financial:L4 C1 Low Operational: L1 C1 Low	MP-06: Security	10/31/2022
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation											96	LGD	FINAL	519	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Prevent Detect Detect, Mitigate Mitigate Detect , Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Operational	3	2							One RR only	MP-06: Security	2021-06-11
2. Pipeline transportation of natural gas			2. Ontario Transportation											97	LGD	FINAL	520	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Detect, Mitigate Prevent	Terrorism & asset security	Operational	3	2							One RR only	MP-06: Security	2021-06-11
1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution											98	LGD	FINAL	521	[redacted]	Murray Costello	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Prevent Detect Detect, Mitigate Mitigate Detect , Mitigate Mitigate Mitigate	Terrorism & asset security	Operational	2	7							One RR only	MP-06: Security	2021-06-11
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation											99	LGD	FINAL	522	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Prevent Detect Detect Mitigate Detect, Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Operational	6	2							H&S, C3, L2, Low Reputation C3, L2, Low	MP-06: Security	2021-06-02
2. Pipeline transportation of natural gas			2. Ontario Transportation											100	LGD	FINAL	523	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Prevent Detect Mitigate	Terrorism & asset security	Health & Safety	2	3							Reputation C3, L2 Low	MP-06: Security	2021-06-11
1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution											101	LGD	FINAL	524	[redacted]	Murray Costello	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Prevent Detect Detect Mitigate Detect, Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Operational	2	7							H&S, C3, L2, Low Reputation C3, L2, Low	MP-06: Security	2021-06-11
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation											102	LGD	FINAL	525	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Prevent Detect Mitigate Detect, Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Financial	6	1							Operational C2, L4, Low	MP-06: Security	2021-06-02
2. Pipeline transportation of natural gas			2. Ontario Transportation											104	LGD	FINAL	526	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Prevent	Terrorism & asset security	Financial	6	1							One RR only	MP-06: Security	6/14/2021
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation											105	LGD	FINAL	527	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Prevent Detect Mitigate Mitigate Detect, Mitigate Mitigate Mitigate Mitigate	Terrorism & asset security	Reputational	4	4						[redacted]	Operational C2, L4, Low	MP-06: Security	2022-06-13
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation											106	LUG	FINAL	528	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Prevent Mitigate Mitigate	Terrorism & asset security	Reputational	3	3							One RR only	MP-06: Security	2021-06-11
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation											108	LGD	FINAL	529	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Prevent Detect Mitigate Detect , Mitigate Mitigate Mitigate Mitigate	Public safety	Health & Safety	1	7						[redacted]	Operational: C2, L2, Low	MP-06: Security	2022-06-21
2. Pipeline transportation of natural gas	2.6. Aggregate		2. Ontario Transportation											109	LGD	FINAL	530	[redacted]	Wes Armstrong	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Mitigate Prevent Mitigate Mitigate	Public safety	Health & Safety	1	7							One RR only	MP-06: Security	2021-12-13
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	531	Contact with poisonous / hostile vegetation / noxious weeds (e.g. poison ivy, oak, sumac, giant hogweed, thorny plants, etc.)	Holly Adams	Encounter with poisonous/noxious weeds or hostile vegetation while working outdoors causing illness and/or physical injury	Employee injury during response	Performing and coming into contact with vegetation	Occupational illness or physical injury from plant encounter	Site Assessment ** Situational Awareness/Communication ** Personal Protective Equipment	Prevent Prevent Prevent	Workforce safety	Health & Safety	4	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	532	Exposure to biological substances (e.g. mould, fungus)	Holly Adams	Inhalation exposure to biological substances (e.g. mould, fungus) associated with water or wet environments as a result of working in or near stagnant water, or moist, wet environments. Generally mould or fungi levels that can cause illness occurs indoors within customer or GDS facilities.	Exposure to airborne contaminants	Working near stagnate water or moist, wet environments where, mould or fungus can be present.	Occupational Illness due to stagnant water, wet environments Encounter with mould and fungus	Site Assessment ** Situational Awareness/Communication ** Personal Protective Equipment Work order communication Program (Maximo)	Detect Prevent Mitigate Prevent	Workforce safety	Health & Safety	1	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	533	Exposure to contaminated food served by an organization sanctioned event	Holly Adams	Foodborne illness caused by digesting contaminated food. Stress caused by concern of exposure to infectious organisms such as bacteria, viruses and parasites could occur where food is prepared /heated/cooked.	Exposure to Biological Contaminants	Improper food hygiene or food storage	Illness due to potential for encounter with microbial through digestion from contaminated food	Food Management and Handling (3rd Party Contractor) *	Prevent	Workforce safety	Health & Safety	2	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	534	Exposure to legionella	Holly Adams	Illness as a result of Inhalation exposure to biological substance, specifically bacteria as a result of water collection within air handling units and operation of cooling towers. Can occur indoors within customer or GDS facilities.	Exposure to airborne contaminants	Improper maintenance of cooling towers or air handling units	Occupational Illness like Lung inflammation caused by infection as a result of exposure to legionella bacterium from operating of cooling towers in office buildings	Maintenance and Inspection program ** Chemical treatment process ** Indoor Environmental Quality Guideline -REWS	Prevent Prevent Prevent	Workforce safety	Health & Safety	1	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	535	Exposure to contagious, infectious viruses/germs (i.e. Hanta Virus, H1N1 Flu, SARs)	Holly Adams	Exposure to new contagious, infectious viruses/germs causing illness and/or elevated anxiety while at work including providing customer service and/or emergency response	Exposure to contagious, infections, or pandemic diseases	General workplace activities (including interreacting with public) which would lead to exposure	Illness due to potential for encounter with contagion	Pandemic Plan / BCP /ERP ** Pre-screening Annual flu program, Situational Awareness ** Personal Protective Equipment Program	Prevent Detect Prevent Prevent Mitigate	Workforce safety	Health & Safety	4	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	536	Pandemic with Community Transmission(e.g. COVID-19)	Holly Adams	Widespread exposure to contagious, infectious viruses/germs causing illness while at work including providing customer service and/or emergency response	Exposure to contagious, infections, or pandemic diseases	General workplace activities (including interreacting with public) which would lead to exposure	Illness due to potential for encounter with contagion	Pandemic Plan / BCP /ERP ** Pre-screening (including rapid test results) Contact Tracing Situational Awareness ** Personal Protective Equipment	Prevent Detect Prevent Prevent Mitigate	Workforce safety	Health & Safety	2	5					TBD - ongoing	Proposed timeline changed to TBD - ongoing on 06/22/2022		MP-04: Health & Safety	6/22/2022
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	537	Exposure to biohazards (e.g. during cross bore investigations, entering a building with animal or bird droppings)	Holly Adams	Exposure causing illness to biohazardous materials while working indoors or outdoors. May be encountered from animal feces or waste products on customer or GDS premises	Exposure to airborne contaminants	Encounter with biohazardous material	Occupational illness due to encounter with biohazardous material	Biohazard Awareness Training Vaccine Program Sewer Safety Program Personal Protective Equipment	Prevent Prevent Prevent Mitigate	Workforce safety	Health & Safety	1	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	538	Exposure to sharps (e.g. used needles and other medical waste)	Holly Adams	Exposure causing illness to biohazardous material while working indoors or outdoors. May be encountered on customer, public or GSD premises.	Exposure to contagious, infections, or pandemic diseases	1. Encounter with sharps contaminated with biohazardous material. 2. Improper security assessments / High Risk Areas not proactively being identified.	Occupational Illness due to encounter with sharps contaminated with biohazardous material	First Aid Training (Standard and Emergency) Situational Awareness/Communication** Personal Protective Equipment	Prevent Prevent Mitigate	Workforce safety	Health & Safety	2	5			Develop educational resources/communications regarding the risks and controls associated with working around sharps. Develop an integrated Sharps Safe Handling and Disposal procedure.	Jae Cho	Q4 2023	Operational: Exposure to Sharps might result in moderate diversion of Enbridge resources.	Operational: L3 C3 Low	MP-04: Health & Safety	7/6/2022
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	539	Exposure to blood borne pathogens	Holly Adams	Exposure causing illness to biohazardous material while working indoors or outdoors. May be encountered on customer, public or GDS premises.	Exposure to contagious, infections, or pandemic diseases	Encounter with body fluids during emergency first aid or contaminated waste	Occupational illness due to encounter with body fluids during emergency first aid or contaminated waste	First Aid Training (Standard and Emergency) Situational Awareness/Communication** Personal Protective Equipment	Prevent Prevent Mitigate	Workforce safety	Health & Safety	3	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	540	Exposure to toxic, explosive or oxygen deficient atmosphere with entry/exit limitations (i.e. confined space)	Holly Adams	Exposure to hazardous atmosphere causing physical injury and/or occupational illness while working in tight areas with entry/exit limitations	Exposure to toxic, explosive or oxygen deficient atmosphere	Exposure to hazardous atmosphere due to work area conditions specific to confined spaces	Physical injury or Occupational Illness due to exposure to hazardous atmosphere due to work area conditions specific to confined spaces	Confined Space Program & Awareness Training** Confined Space Entry Program & Training (STO)** Confined Space Identification and Labelling Hot Work Program and Training (STO)** Working in Gas Atmosphere Program and Training* Technical Learning Competency Program Personal Protective Equipment Site Assessment** Situational Awareness**	Prevent Prevent Prevent Prevent Prevent Prevent Mitigate Detect Prevent Prevent	Workforce safety	Health & Safety	3	5								MP-04: Health & Safety	6/3/2021

Division - Sub	Division - Type	Division - Division	Division (L1) - Executive	Division (L2) - Vice	Division (L3) - Director	Division (L4) - Manager	Division (L5) - Supervisor	Division (L6) - Department	Division	Division - Type 2	Division (L7) - Leadership Committee	Division - Segment	Division - Function	Agency ID	Agency	Incident	Incident	Title	Work Begun	Incident Description	Hazard (Primary) Personal	Hazard (Secondary) Personal	Incident Description	Work Category	Work Category - Detail	Incident Category	Incident Type	Lost Time	Work Begun	Incident Root Cause Description	Incident Root Cause	Comments	Investigation Work Ranking	Investigation Manager (Last) - Incident	Date Added to SAFETY Database
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Contact with buried underground utilities (excluding gas)	Kelly Adams	Transfer of energy due to inadvertent contact with buried utilities resulting in physical injury or elevated stress	Accidental exposure to electrical voltage	Excavating (via machinery or hand digging) around buried utilities other than gas (e.g. electrical)	Physical injury due to contact causing transfer of electrical energy		Guidelines for Excavations (LOC) Electrical Safety Program and Training** Forward Disturbance Program Ground Disturbance Program** Identification and Labelling Site Assessment** Situational Awareness/Communication** Personal Protective Equipment Life Saving Rules	Forward Forward Forward Mitigative Forward Forward Forward Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Transfer of electricity (static) resulting in microshock	Kelly Adams	Transfer of static discharge causing ignition source resulting in physical injury or elevated stress	Accidental exposure to electrical voltage	Working where there is potential for static electricity transfer (e.g. with plastic pipe that is ungrounded/not gas)	Physical injury due to transfer of static energy due to an instantaneous electrical charge with flammable source present		Emergency Response Plan and Training Working in Gas Atmosphere Program and Training** Hot Work Program and Training (ESTID)** Fire Extinguisher Awareness and Training Personal Protective Equipment Site Assessment** Situational Awareness**	Forward Forward Forward Mitigative Forward Forward Detect Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Contact with overhead utilities (e.g. power lines)	Kelly Adams	Transfer of electrical energy due to contact with overhead utilities causing physical injury. Maybe encountered on customer, public or ESS premises.	Accidental exposure to electrical voltage	Operating equipment (e.g. backhoe, boom truck, hydro excavation equipment)	Physical injury due to contact causing transfer of electrical energy		Electrical Safety Program and Training** Working Near Overhead Wires Procedure Site Assessment** Situational Awareness/Communication** Personal Protective Equipment Life Saving Rules	Forward Forward Forward Mitigative Forward Forward Detect Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Contact with high voltage (i.e. 750 Volts) electrical systems (not exposure to electrical arc flash)	Kelly Adams	Transfer of energy due to contact with high voltage electrical system or as a result of arc flash resulting in physical injury	Accidental exposure to electrical voltage	Working on or near energized equipment (e.g. troubleshooting, diagnostics, operating breaker switches), during inclement weather	Physical injury due to electrical explosion or discharge resulting from a connection through air to ground or another electrical system		Electrical Safety Program and Training** Lockout/Tag out Program and Training* Technical Learning Competency Programs (Electrician) Fire Extinguisher Awareness and Training Signage/Alerts Site Assessment** Situational Awareness/Communication** Personal Protective Equipment Life Saving Rules	Forward Forward Forward Forward Mitigative Forward Detect Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Exposure to electrical energy	Kelly Adams	Electrical energy flowing through the body as a result of contact with an electrical energy source causing physical injury	Accidental exposure to electrical voltage	Using damaged tools or equipment (exposed wiring), overloading circuits, using tools in wet environments, improper bonding or grounding, reduced current	Physical injury due to exposure to open electrical current. Into the body		Electrical Safety Program and Training** Tool Inspection Program** Troubleshooting/Current Isolation Site Assessment** Situational Awareness/Communication** Personal Protective Equipment	Forward Forward Mitigative Forward Forward Mitigative	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Welding flash	Kelly Adams	Exposure to radiation while welding and cutting causing physical injury. May occur in the work/shop for prefabrication or on site field welding	Exposure to ultraviolet radiation	Welding, in the work shop or in the field	Physical injury due to burns (i.e. eye, skin) from exposure to radiation		Working in Gas Atmosphere Program and Training** Hot Work Program and Training (ESTID)** Technical Learning Competency Programs (Welding) Personal Protective Equipment Site Assessment** Situational Awareness**	Forward Forward Forward Mitigative Forward Forward Detect Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Fatigued and Sustained Postures	Kelly Adams	Positioning of the body that deviates significantly from the neutral position while performing work activities that can result in physical injury. May occur in the work/shop or on site in the field and will cause muscle fatigue and disrupt blood flow, leading to physical injury.	Exposure to musculoskeletal Risk Factors	Work activities in office or vehicle (e.g. Keyboard, monitor placement, communication devices, smart phone, laptop), work in the field (e.g. Tool use, lifting, pushing/pulling, awkward postures), work in the shop (e.g. Lifting, pushing/pulling, tool use), or in a vehicle (e.g. on roadside, snow), working in restricted space and (e.g. trench including large diameter pipe, bell hole, stations etc.), or your back and on ladders. Includes prolonged whole body posture such as sitting or standing for long periods.	Physical injury due to activities that require an awkward posture (or awkward position of the body) and/or repetitive movements that can result in musculoskeletal injury (e.g. sitting, standing) for an extended period		Ergonomic Program and Training Integrated Ergonomics Program and Training Integrated Ergonomics Design in office equipment, workspaces and in field (e.g. hand tools, engineering design specs) Integrated Ergonomics Design in office equipment, workspaces and in field (e.g. hand tools, engineering design specs) Objective Assessment Tool (Assessments) Integrated Ergonomics Design in office equipment, workspaces and in field (e.g. hand tools, engineering design specs) Site Assessment** Vehicle Design Standards** Situational Awareness** Integrated RTC Process (Integrated Ice Change) Process Standard Operating Procedures (e.g. Water Recharge Procedure)*; valve maintenance*	Forward Forward Mitigative Forward Forward Forward Forward Forward Forward Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Contact Stress	Kelly Adams	Part of the body rubbing against or pushing on a component of the workstation or workplace (e.g. desk corners, edge of tools, hard, uneven surface, single finger load trigger) resulting in physical injury	Exposure to musculoskeletal Risk Factors	Working in an office (i.e. typing or mousing) where there is ongoing contact of wrists, sitting where there is pressure on back of knees, outdoor activities such as kneeling on hard (e.g. sidewalk grating or uneven ground, hand tool use	Physical injury/early positioning or contact with parts of the body may cause irritation or blood vessels constriction		Ergonomic Program and Training Integrated Ergonomics Program and Training Integrated Ergonomics Design in office equipment, workspaces and in field (e.g. hand tools, engineering design specs) Integrated Ergonomics Design in office equipment, workspaces and in field (e.g. hand tools, engineering design specs) Site Assessment** Situational Awareness/Communication** Personal Protective Equipment Notification Process * Integrated RTC Process	Forward Forward Mitigative Forward Forward Forward Forward Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Conducting tasks in the office or in the field that cause muscle strained joints to contract and relax repetitively (e.g. typing, for contact can injure nerves or other tissues. Extreme high forces can cause acute injury.	Kelly Adams	Conducting tasks in the office or in the field that cause muscle strained joints to contract and relax repetitively (e.g. typing, for contact can injure nerves or other tissues. Extreme high forces can cause acute injury.	Exposure to Musculoskeletal Risk Factors	Manual material handling tasks including carrying, lifting, pushing, or pulling of heavy or large materials, equipment, or tools. Forceful movements (e.g., bending, extending, static loading) and gripping tools. Use of hand or knee on a hammer.	Physical injury due to lowering/high force to lift or handle materials or equipment, or high force to grip tools or equipment. Injuries include strain and sprains found in wrists by applying force.		Ergonomic Program and Training Integrated Ergonomics Program and Training Integrated Ergonomics Design in office equipment, workspaces and in field (e.g. hand tools, engineering design specs) Situational Awareness/Communication** Site Assessment** Vehicle Design Standards** Notification Process * Integrated RTC Process	Forward Forward Mitigative Forward Forward Forward Forward Forward Forward	Workforce safety	Health & Safety	0	N		Mine 1 lift description proposed to target the appropriate hazard and consequence Developed website page is missing for Lebanon Training Needs Analysis - Lebanon to provide specs and delete work surfaces Assessment of Ergonomic program integrations to comply with enterprise specifications Lebanon to go live with Ergonomic Program	Mine Loader	2022	Proposed timeline changed from 2021 to 2022 on 09/22/2020 and Sharepoint added to title Q4 2022 Update: Terms complete – 2022 workshop planned to follow up in 2023 annual risk review			MP-SI: Health & Safety	2020-09-01
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Repetitive Movements	Kelly Adams	Tasks that require repetitive movement without sufficient recovery time and sufficient injury cycle (proportion of time body is working) resulting in physical injury.	Exposure to Musculoskeletal Risk Factors	Repetitive motions of the whole body (climbing ladder, shoveling) or handle/arm when using tools or equipment (e.g. welding with mouse, using hand tools, using thumbs to type on email or cell phone, work on control panel).	Physical injury to activities that require repeated movements persistently without rest that in conjunction with excessive force or awkward positions		Ergonomic Program and Training Integrated Ergonomics Program and Training Integrated Ergonomics Design in office equipment, workspaces and in field (e.g. hand tools, engineering design specs) Integrated RTC Process Work Planning Process	Forward Forward Mitigative Forward Forward Forward Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Static Postures	Kelly Adams	Activities that require the same positions to be maintained (e.g. sitting, standing) for an extended period of time in the office or the field can result in physical injury	Exposure to Musculoskeletal Risk Factors	unchanged whole body (i.e. standing or sitting in a vehicle, at a desk), prolonged sitting in a vehicle or at a desk, use of objects for extended period of time (e.g., phone, tablet, smartphone), operating equipment (e.g. southern crew, backhoe), holding finger	Physical injury due to limited movement or change in posture can cause additional muscle fatigue and disrupt blood flow		Ergonomic Program and Training Integrated Ergonomics Program and Training Integrated Ergonomics Design in office equipment, workspaces and in field (e.g. hand tools, engineering design specs) Situational Awareness/Communication** Site Assessment** Notification Process * Integrated RTC Process	Forward Forward Mitigative Forward Forward Forward Forward Forward Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Contact with buried, hidden or unprotected gas line	Kelly Adams	Exposure to pressurized natural gas due to inadvertent contact with plant utilities causing physical injury. May be encountered on customer, public or ESS premises.	Exposure to energized systems (compressed gas)	Working the ground using mechanical or hand tools, coming into contact and causing damage to plant (e.g. hitting meters, pipes)	Physical injury due to contact with plant causing transfer of energy and exposure to natural gas		Guidelines for Excavations (LOC) Emergency Response Plan and Training Forward Disturbance Program Working in Gas Atmosphere Program and Training** Fire Extinguisher Awareness and Training Personal Protective Equipment Site Assessment** Situational Awareness**	Forward Forward Forward Mitigative Forward Forward Forward Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Working with natural gas in confined spaces	Kelly Adams	Exposure to pressurized natural gas and potential for fire due to loss of containment while conducting maintenance and construction activities with, on or near natural gas equipment (e.g. pipelines, compressors or metering) sites. May be encountered on customer, public or ESS premises.	Working with flammable materials (ignition hazards)	Conducting maintenance activities, topping, stopping, purging, purging, and maintaining NGV stations, and welding operations.	Physical injury due to loss of containment of natural gas leading to fire incidents		Working in Gas Atmosphere Program and Training** Lockout/Tag out Program and Training* Technical Learning Competency Program Fire Extinguisher Awareness and Training Personal Protective Equipment Site Assessment** Situational Awareness** Life Saving Rules	Forward Forward Forward Mitigative Forward Forward Detect Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Taking measurements at Set Cut - natural gas plant or equipment	Kelly Adams	Exposure to pressurized natural gas and potential for fire due to loss of containment leading to physical injury or elevated stress. May occur while completing measurements on Set Ties at customer or ESS premises.	Accidental release/LOC flammable gas	Installing and reading pressure gauges on Set Ties using valve and test point	Physical injury due to contact with plant pipe causing transfer of energy and exposure to natural gas		Working in Gas Atmosphere Program and Training** Lockout/Tag out Program and Training* Technical Learning Competency Program Fire Extinguisher Awareness and Training Personal Protective Equipment Site Assessment** Situational Awareness**	Forward Forward Forward Mitigative Forward Forward Detect Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Working with natural gas in/on confined spaces	Kelly Adams	Conditions arise where work potential for fire incidents causing physical injury or elevated stress. May be encountered on customer, public or ESS premises.	Accidental release/LOC flammable gas	Working with natural gas during mode lock investigation, blowing gas conditions during damage or responding to an emergency, working within an emergency evacuation zone	Physical injury due to gas release potentially leading to fire incidents		Emergency Response Plan and Training Working in Gas Atmosphere Program and Training** Lockout/Tag out Program and Training* Technical Learning Competency Program Fire Extinguisher Awareness and Training Personal Protective Equipment Site Assessment** Situational Awareness**	Forward Forward Forward Mitigative Forward Forward Detect Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Work from an elevated surface	Kelly Adams	Working in or near fall surfaces as a result of exposure to high temperatures (i.e. up to +200°C or hot sources e.g. natural gas equipment, physical injury. Encountered on ESS projects or ESS stations or customer and public premises and larger plant.	Exposure to heat stress	Maintaining and working near hot piping (e.g. self-latch heater, turbo-charger on recips, discharge pipings), boilers and liter heating systems including pumps, tanks, side glands and topping up at Crawford gas (LP, NRU), engines, exhausts	Injury due to physical contact with hot material or equipment		Working in Gas Atmosphere Program and Training** Lockout/Tag out Program and Training* Technical Learning Competency Program Site Assessment** Situational Awareness**	Forward Forward Forward Mitigative Forward Forward Detect Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Work from contact with hot surfaces	Kelly Adams	Working in or near hot surfaces as a result of exposure to high temperatures (i.e. up to +200°C or hot sources e.g. natural gas equipment, physical injury. Encountered on ESS projects or ESS stations or customer and public premises and larger plant.	Exposure to heat stress	Maintaining and working near hot piping (e.g. self-latch heater, turbo-charger on recips, discharge pipings), boilers and liter heating systems including pumps, tanks, side glands and topping up at Crawford gas (LP, NRU), engines, exhausts	Injury due to physical contact with hot material or equipment		Working in Gas Atmosphere Program and Training** Lockout/Tag out Program and Training* Technical Learning Competency Program Site Assessment** Situational Awareness**	Forward Forward Forward Mitigative Forward Forward Detect Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Working in or near fall surfaces as a result of exposure to high temperatures (i.e. up to +200°C or hot sources e.g. natural gas equipment, physical injury. Encountered on ESS projects or ESS stations or customer and public premises and larger plant.	Exposure to heat stress	Maintaining and working near hot piping (e.g. self-latch heater, turbo-charger on recips, discharge pipings), boilers and liter heating systems including pumps, tanks, side glands and topping up at Crawford gas (LP, NRU), engines, exhausts	Injury due to physical contact with hot material or equipment		Working in Gas Atmosphere Program and Training** Lockout/Tag out Program and Training* Technical Learning Competency Program Site Assessment** Situational Awareness**	Forward Forward Forward Mitigative Forward Forward Detect Forward	Workforce safety	Health & Safety	0	N							MP-SI: Health & Safety	8/9/2021
E. Aggregate	E.5. Aggregate		E. Aggregate	E.AG. ESO Aggregate	E.N.S. Aggregate									Nine 2021		FINAL	930	Work from contact with hot

First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version	Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard	Source	Consequences	Controls	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	577	Exposure to designated substances (mercury)	Holly Adams	Exposure to soil or stations contaminated with mercury can cause occupational illness while working within designated areas of GDS facilities including Hagar LNG Plant.	Exposure to designated substances	Station or plant maintenance and construction activities. Field work where there is mercury contaminated facilities or soil	Overexposure to mercury through ingestion or inhalation can cause occupational illness.	Hazardous Materials Program and Awareness Training** Designated Substance Program and Awareness Training** Mercury Management Program* Personal Protective Equipment Site Assessment** Situational Awareness**	Prevent Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	4	4								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	578	Exposure to designated substances (lead)	Holly Adams	Exposure to materials contaminated with lead can cause occupational illness while working within designated areas of GDS facilities or on customer premises.	Exposure to designated substances	Working with or near lead containing material (e.g. legacy materials specifically, paint, pipe dope, solder) in the field, GDS facilities, station maintenance, and asset maintenance (i.e. Meters, appliances)	Overexposure to lead through ingestion or inhalation can cause occupational illness.	Hazardous Materials Program and Awareness Training** Designated Substance Program and Awareness Training** Industrial Hygiene Program ** Medical Monitoring including PB surveillance program Personal Protective Equipment Ratification Process * Site Assessment** Situational Awareness**	Prevent Prevent Prevent Prevent Mitigate Prevent Detect Prevent	Workforce safety	Health & Safety	7	3			GDS 2021 sustainment testing plan finalized for implementation Development of Housekeeping subcommittee to create recommendation on how operations will execute on lead management program housekeeping requirements Presentation to leadership regarding lead management program delivered Included designated substances in GDS Risk Register workshops Execution of sustainment testing Execution plan for housekeeping sustainment for vehicles and workspaces Final summary communication to leaders and employees	Altaira Hildebrand	2022	06/22/2022 proposed timeline changed from 2021 to 2022 Q4 2022 Update: - Focused audit - completed - Focused communication on medical monitoring program – planned for Q1 - Annual evaluation of all program controls completed and combined with audit results – action plan developed for improvements Treatment plan complete - 5/2/2023		MP-04: Health & Safety	2023-05-02
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	579	Contact with pipeline coal tar tape coatings	Holly Adams	Exposure to coal tar and coal tar pitch residue (e.g. irritant smoke) due to hot application of tape coatings can lead to occupational illness while working on GDS pipelines (i.e.. pipe joints) or stations.	Exposure to designated substances	Pipeline and station maintenance specific to coating sampling and handling for disposal, new pipeline construction	Occupational illness due to inhalation of smoke or vapour generated by hot application process can cause irritation to the eyes, skin and respiratory tract. Longer term exposure may cause photosensitization of the skin	Hazardous Materials Program and Awareness Training** Technical Learning Competency Program Personal Protective Equipment Site Assessment** Situational Awareness** Pipeline Coatings, Handling, Storage and Disposal**	Prevent Prevent Mitigate Detect Prevent Prevent	Workforce safety	Health & Safety	6	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	580	Exposure to total particulate other than heavy metals	Holly Adams	Generation of airborne total particulate can cause occupational illness while working within GDS facilities, on customer and public premises.	Exposure to airborne contaminants	Activities that cause airborne particulate (e.g. vehicle emissions, machinery and industrial processes (e.g. sanding, burning) working within a contaminated environment (i.e. post fire, burning residue).	Occupational illness due to inhalation causing overexposure of fine airborne particulate generated mechanical finishing processes, vehicle operation and industrial processes	Weld Shop Mechanical Ventilation Standard and management program** Hazardous Materials Management Program and Awareness Training Personal Protective Equipment including Respirator Fit Testing Site Assessment** Situational Awareness**	Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	4	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	581	Exposure to Volatile organic compounds (VOC's)	Holly Adams	Exposure due to release of vapour into the atmosphere can cause occupational illness while working within GDS facilities including stations and commercial customer premises.	Exposure to toxic, explosive or oxygen deficient atmosphere	Working with or in proximity to solvents or hydrocarbon containing materials (e.g. paint, part cleaning solution, toner, sealant compounds)	Overexposure to VOC's may cause upper respiratory tract irritation and occupational illness	Hazardous Materials Management Program and Awareness Training Personal Protective Equipment Site Assessment** Situational Awareness**	Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	3	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	582	Exposure to contaminated potable water	Holly Adams	Exposure by ingestion of contaminated water can cause occupational illness at remote GDS facilities where public water systems are not accessible.	Exposure to contagious, infections, or pandemic diseases	Drinking water, showering, dishwashing, hand washing, and general personal water usage at remote locations where municipal water source is not available	Overexposure through ingestion of contaminated water supply can cause occupational illness	Hazardous Materials Program and Awareness Training** Site Assessment** Situational Awareness** Suspect Soils Program*	Prevent Detect Prevent Prevent	Workforce safety	Health & Safety	3	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	583	Working with liquefied natural gas (LNG)	Holly Adams	Extreme cold temperatures (-150C) caused by exposure to the LNG can cause physical injury.	Exposure to cold stress	Cryogenically cooled natural gas to a liquid state	Skin contact can cause physical injury	Hazardous Materials Management Program and Awareness Training** Technical Learning Competency Program (Refrigerant/LNG Operator)* Engineering control - vent to atmosphere and insulation Personal Protective Equipment (cryogenic PPE) Site Assessment** Situational Awareness**	Prevent Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	2	4								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	584	Working with refrigerants during the processing of liquefied natural gas (LNG)	Holly Adams	Exposure to cold temperatures (up to -44C) can cause physical injury at GDS LNG facility. - Cryogenically cooled natural gas to a liquid state	Exposure to cold stress	Working with equipment during mixing of refrigerants (pentane, butane, ethane, propane and methane) within a closed system.	Skin contact can cause physical injury	Hazardous Materials Management Program and Awareness Training** Gas Certification Requirements (LNG Plant Operator)* Engineering control - internal system processing Personal Protective Equipment Program Site Assessment** Situational Awareness**	Prevent Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	2	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	585	Transportation of hazardous materials	Holly Adams	Exposure to hazardous materials through road transportation related functions can cause physical injury or occupational illness at GDS facilities.	Accidental release/LOC flammable gas	Offering for transport, transporting, receiving hazardous materials	Physical injury due to contact with hazardous materials during transport	Hazardous Materials Management Program and Awareness Training Transportation of Dangerous Goods Program and Training * Personal Protective Equipment Site Assessment** Situational Awareness**	Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	4	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	586	Exposure to unfamiliar environments or conditions of travel e.g. air travel	Holly Adams	Travelling for business purposes in unfamiliar locations and on unfamiliar routes i.e. different modes of transportation; hotel stays.	Worker fatigue	Business travel	Occupational illness due to anxiety causing stress as a result of lack of control and unfamiliar environment	Travel Safety* Emergency Response Plan and Training Site Assessment** Situational Awareness/Communication	Prevent Prevent Detect Prevent	Workforce safety	Health & Safety	4	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	587	Contact with sharp objects	Holly Adams	Contact while working with or near sharp edges or cutting tools that could cause physical injury. Can occur in GDS facilities, customer premises or public places.	Employee injury during response	Working with/around/near sharp objects (e.g. edges of shoring boxes, utility knives, side cutters, snips, scalpels, razor blades, metal cutters, unguarded saw, etc.)	Physical injury due to contact of a body part with a shear or cutting point or sharp edges may cause lacerations, contusions, crushing of tissue, puncture and broken bones.	Manual material handling training Tool Inspection Program and Training* Personal Protective Equipment Site Assessment Situational Awareness**	Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	6	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	588	Caught in / Entanglement	Holly Adams	Physical Injury as a result of a body part or an accessory (e.g. clothing, hair, jewelry), becoming caught within a movable element of machinery. Can occur in GDS facilities, customer premises or public places.	Compressed, pinched, or crushed by	Working with or near machinery, equipment, and tools, etc. that have unguarded moving parts	Entanglement causing physical injury at a point of operation where energy is transmitted (e.g. pulleys, belts, chains, gears) through moving parts of a machine.	Manual material handling training Request For Change Program (PSHSR) Tool Inspection Program (e.g. guards) and Training* Personal Protective Equipment Site Assessment Situational Awareness**	Prevent Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	2	4								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	589	Struck by vehicles on work site (e.g. depot, office, station, warehouse, public roadways)	Holly Adams	Forcible contact or impact between a person and a vehicle resulting in physical injury. May be encountered on customer, public or GSD premises.	Exposure to Mechanical Energy	Working near or directing vehicles (e.g. trucks, dump truck, cars, delivery trucks, etc.); working outdoors on or near roadways, construction sites and public traffic; walking outside	Contact causing physical injury between person and machine as a result of working in close proximity to moving vehicles	Spotter Training Traffic Control Plans and Training Traffic Barriers Pipeline Construction Training * Visitor Site Orientation Personal Protective Equipment Site Assessment** Situational Awareness**	Prevent Prevent Mitigate Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	3	5								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	590	Exposure to energized systems (i.e. mechanical, hydraulic or pneumatic, thermal, gravitational energy).	Holly Adams	Physical injury as a result of contact with tools, equipment or materials due to uncontrolled release of energy. Can occur at any site workers are present including GDS facilities, customer premises or public places.	Exposure to energized systems (compressed gas)	Encounter with energized systems i.e. pressurized equipment (e.g., Hydrovacs, backhoes, excavators, pavement breakers, spring loaded materials), live plant	Physical injury due to unintended release of primary, residual or stored energy causing contact between person and tool, equipment, or material.	Emergency Shutdown (STO) Procedure Lockout/Tagout Program and Training* Hot Work Program and Training (STO)** Tool Inspection Program** Personal Protective Equipment Site Assessment** Situational Awareness/Communication** Life Saving Rules	Prevent Prevent Prevent Prevent Mitigate Detect Prevent Prevent	Workforce safety	Health & Safety	3	4								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	591	Exposure to vibration (whole body/segmental)	Holly Adams	Activities that cause vibration at the hands through use of a hand tool (e.g. drill, grinder) or through the feet (if standing) or buttocks (if sitting) (e.g. heavy equipment) can occur in GDS facilities, vehicles or public areas resulting in physical injury and in some cases occupational illness (Reynaud's disease).	Exposure to Mechanical Energy	Using vibrating tools/equipment, including heavy machinery (e.g. chainsaw, jackhammer, impact wrench, work equipment etc.); operating large machinery and vehicles	Physical injury due to segmental (hand/arm) vibration can contribute to limited mobility and joint pain, reduced circulation, and whole body vibration can lead to mechanical injuries of muscle or soft tissue and disease (i.e. degenerative disc disease).	Field Ergonomics Program and Training * Integrated Office Ergonomics Program and Training Integrated Ergonomic Design in office equipment, workspaces and in field (e.g. hand tools, engineering design specs) Personal Protective Equipment Ratification Process * Integrated RFC Process Work Planning Process	Prevent Prevent Prevent Mitigate Prevent Prevent Prevent	Workforce safety	Health & Safety	3	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	592	Contact with hot materials (i.e. tape coat, anodes, welding slag) and heat sources	Holly Adams	Working in or near hot materials generated from hot work operations causing physical injury. Encountered on GDS property at GDS stations or customer and public premises.	Exposure to heat stress	Hot work operations including tape coating, cadwelding (anodes), welding that generate hot materials e.g. during pipeline maintenance	Physical injury due to physical contact with hot materials causing burns or fire from sparks or flash	Working in Gas Atmosphere Program and Training** Technical Learning Competency Program (Gas Technician, Welder) Personal Protective Equipment Site Assessment** Situational Awareness**	Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	4	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	593	Working environment - poor lighting conditions	Holly Adams	Conducting work at light levels that impede the workers tasks causing physical stress (i.e. loss of focus, frustration) and physical injury (e.g. eye strain, headaches) . Can occur at any site workers are present including GDS facilities including offices, customer premises or public places.	Exposure to Muskoskeletal Risk Factors	Working under poor (e.g. low lighting, glare, shadows) conditions indoors (i.e. stations, office) or outdoors (i.e. at night, dawn, dusk)	Occupational illness due to inadequate lighting (i.e. inappropriate levels, glare, shadows) increases task difficulty leading to higher stress and increases eye fatigue, strain and headaches.	Integrated Ergonomic Design in office equipment, workspaces and in field (e.g. task lighting, facility design specs) Work Planning Process PPE (eyewear program)* Site Assessment** Situational Awareness/Communication**	Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	4	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	594	Cold stress	Holly Adams	Exposure to extreme cold temperature or extremely cold materials can cause occupational illness and physical injury. Encountered on GDS property at GDS stations or customer and public premises.	Exposure to cold stress	Working in cold temperature conditions e.g. winter outdoors	Occupational illness due to cold stress occurs by driving down the skin temperature, and eventually the internal body temperature. Skin exposure or contact may accelerate frost bite	Extreme Temperature Awareness* Work Planning Process PPE Site Assessment** Situational Awareness/Communication**	Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	4	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	595	Exposure to poor indoor air quality	Holly Adams	Working in conditions of poor indoor air quality can cause occupational illness at any site workers are present including GDS offices and facilities.	Exposure to toxic, explosive or oxygen deficient atmosphere	General workplace activities including office tasks in areas with inadequate relative humidity levels, temperatures, etc.	Occupational illness due to poor indoor air quality may cause occupational illness, irritation, or sensitization (e.g. allergy) or accentuate existing condition (e.g. asthma) symptoms	Indoor Air Quality Program** Facility Management Program including Facility Monitoring i.e. Andover system** Building Inspections (JHSC)	Prevent Prevent Detect	Workforce safety	Health & Safety	4	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	596	Personal noise exposure to elevated noise levels (>85dbA) (Physical Agents-Noise	Holly Adams	Exposure to prolonged or excessive levels of noise can cause temporary change in hearing or occupational illness (i.e. permanent loss), and psychological stress and cognitive impairment.	Exposure to elevated noise > 85dBa	Worker exposure while operating tools with excessive noise levels, entering buildings or rooms containing equipment with excessive noise levels. Working on construction sites, working with tools/equipment, compressor sites, blowing down lines	Occupational illness due to excessive noise levels generated at the source with ineffective barriers in place to reduce exposure can cause short term or long term/permanent damage at the ear.	Hearing Conservation Program including Signs, Barriers, Training Audiometric Testing Field Equipment Design (e.g. hand tools, engineering design specs, noise dampening accessories) Personal Protective Equipment Situational Awareness/Communication** Ratification Process * Integrated RFC Process	Prevent Detect Prevent Mitigate Prevent Prevent Prevent	Workforce safety	Health & Safety	7	3			Reviewed proposed Enterprise Hearing Loss Prevention Program Specification Action plan developed based on proposed standard Integration project plan endorsed Review of LUG audiometric data to confirm additional controls are not required. Implement LUG program with HLPP additions across GDS	Jae Cho	2022	Proposed timeline changed from 2021 to 2022 on 06/20/2022 Q4 2022 Update: - Tactics complete – 2023 workshop planned as follow-up to 2022 annual risk review		MP-04: Health & Safety	2023-01-31
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	597	Heat Stress	Holly Adams	Exposure to extreme hot temperature can cause occupational illness. Encountered on GDS property at GDS stations or customer and public premises.	Exposure to heat stress	Working in hot temperature conditions e.g. summer outdoors, indoors with radiant heat from equipment	Heat stress occurs when the body is under stress from overheating causing heat-related illnesses or occupational illness.	Extreme Temperature Awareness* Work Planning Process PPE Site Assessment** Situational Awareness/Communication**	Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	4	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	598	Exposure to ionizing (e.g. NORM, x-rays) and non-ionizing radiation	Holly Adams	Exposure to prolonged or excessive levels of radiation can cause occupational injury	Exposure to ultraviolet radiation	Exposure to welding x-rays, XRF handheld device, exposure to oil and gas residue (NORM waste) during pigging or maintenance operations	Prolonged exposure to ionizing radiation can cause occupational illness	"Hazardous Materials Program and Awareness Training** Radiographic testing certification Personal Protective Equipment Site Assessment** Situational Awareness/Communication** NRCAN XRF certification prior to XRF use"	Prevent Prevent Mitigate Detect Prevent Prevent	Workforce safety	Health & Safety	2	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	599	Exposure to ultraviolet radiation (e.g. sun)	Holly Adams	Exposure to prolonged or excessive levels of ultraviolet radiation can cause physical injury. Encountered outdoors on GDS property at GDS stations or customer and public premises.	Exposure to ultraviolet radiation	Field work outdoors where exposed to sunlight	Physical injury from UV radiation from sunlight will burn unprotected skin	Extreme Temperature Awareness* Work Planning Process Personal Protective Equipment Program Site Assessment** Situational Awareness/Communication**	Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	3	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	600	Drowning	Holly Adams	Working over or near water, where the danger of drowning exists. Encountered outdoors on GDS property at GDS stations or customer and public premises including during leak and corrosion survey.	Employee injury during response	Working on or near water, working over bridges, etc.	Falling into water may cause cold shock and immersion, inhalation of water or drowning leading to physical injury or occupational illness.	Facilities Management near fire ponds (STO)* Emergency Response Plan and Training Fall Protection Program Working from Heights training Personal Protective Equipment Site Assessment** Situational Awareness/Communication**	Prevent Prevent Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	2	5								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	601	Exposure to adverse / inclement weather (includes wind, rain, sleet, lightning; excluding heat and cold)	Holly Adams	Exposure to extreme conditions during inclement weather can cause physical injury or increase stress . Encountered outdoors on GDS property at GDS stations or customer and public premises. - Working in inclement weather (snow storms, thunderstorms, severe weather, earthquakes, etc.)	Weather and Outside Forces	Environmental Hazard Exposure	Severe weather can create worksite hazardous conditions and exposure to outdoor element resulting in physical injury	**Emergency Response Plan** and Training Workplace Emergency Preparedness Training Personal Protective Equipment Site Assessment** Situational Awareness/Communication**	Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	2	4								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	602	Workplace Violence and Harassment (internal)	Karen Graham	Stress or physical injury due to exposure to actions or behavior where there is a threat or potential exercise of physical force (e.g. hitting, throwing objects, sexual violence, or threats) by a person against a worker, or where the external party engages in unwelcome vexatious comment or conduct against a worker in a workplace including sexual harassment (e.g. innuendo, lack of civility and respect, sexual solicitation or advance). Encountered on GDS facilities including offices.	Vandalism/terrorism/security	Work activities that require interaction with internal employees (i.e. co-workers, management, contractors)	Situations of workplace violence and harassment cause increased mental stress and physical injury.	Workplace Violence Program and training** Anti harassment policy Active Intruder Training* Shelter in Place Training* Diversity in the Workplace Program Employee and Family Assistance Program (EFAP) Site Assessment** Situational Awareness/Communication**	Prevent Prevent Prevent Prevent Prevent Prevent Detect Prevent	Workforce safety	Health & Safety	4	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	603	Workplace Violence and Harassment (external)	Karen Graham	Stress or physical injury due to exposure to actions or behavior where there is a threat or potential exercise of physical force (e.g. hitting, throwing objects, sexual violence, or threats) by a person against a worker, or where the external party engages in unwelcome vexatious comment or conduct against a worker in a workplace including sexual harassment (e.g. innuendo, lack of civility and respect, sexual solicitation or advance). Encountered on GDS facilities, customer premises or public places.	Vandalism/terrorism/security	Work activities that require interaction with internal employees (i.e. co-workers, management, contractors)	Situations of workplace violence and harassment cause increased mental stress and physical injury.	Workplace Violence Program and training** Active Intruder Training* Shelter in Place Training* Work order communication Program (Adventex, Maximo)** Lone Worker Program ** Anti harassment policy Employee and Family Assistance Program (EFAP) Site Assessment** Situational Awareness/Communication** Site/Building Security** Emergency Response and Preparedness	Prevent Prevent Prevent Prevent Prevent Prevent Prevent Detect Prevent Mitigate Prevent	Workforce safety	Health & Safety	3	4								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	604	Fatigue	Holly Adams	Fatigue related stress can occur in workers engaged in high demand jobs, safety sensitive tasks, long duty periods, and shiftwork that disrupt the circadian rhythms causing accumulative sleep debt.	Worker fatigue	Working (including driving) extended hours, long hours of physical or mental activity, or insufficient break time between shifts (e.g. on-call work, emergency work, scheduled overtime), responding to shiftwork challenges and schedules	Fatigue or the body's response to sleep loss or to prolonged physical or mental exertion can impact the psychological well-being of a worker causing stress related occupational illness	Control Room Management Fatigue Management Program * and Training Employee and Family Assistance Program (EFAP) Situational Awareness/Communication** Hours of Work and overtime Program Hours of Work Policy Alternate work (AWA) program	Prevent Prevent Prevent Prevent Prevent Prevent Prevent	Workforce safety	Health & Safety	4	5								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	605	Emotional or Cognitive Mental Stress	Holly Adams	Emotional and Cognitive mental stress (from internal and/or external factors) leading to a workplace personal safety incident/occupational illness	Employee injury due to Psychosocial Stressors	Ongoing interruptions, unaddressed conflict, working during periods of extreme stress (including pandemic conditions) or organizational change, response to a critical incident (e.g. employee death, emergency response)	Workplace personal safety incident	> Employee and Family Assistance Program (EFAP) > Workplace Mental Health Program (Working Minds) > Onsite Counselling following traumatic events > Wellness program (Health Check Assessment, > LifeSpeak, Financial Advisory) > Reflection and Quiet Rooms > Health Services Teams (Counselling and Coaching) > Stigma reduction - EGD Safety Gala > People Leader relationships (1:1 Conversations, Team Check ins) > Well being goal focus (Team and Personal) > Mentorship program for organizational changes > Heightened Leadership mental health education (Overall recognition and support) > New Health check assessment > CAN/CSA Z1003 (Psychological Health & Safety in the Workplace) >Financial Advisory Supports > Hazard Assessment process (FLHA): Human factors, Fit for duty	Prevent Prevent Mitigate Prevent/Detect Prevent Mitigate Prevent/Detect Prevent/Detect Prevent Prevent/Detect Detect Prevent/Detect Prevent Prevent Detect	Workforce safety	Health & Safety	4	5						Description and controls updated following the re-evaluation workshop. Results finalized - July 27, 2022		MP-04: Health & Safety	10/31/2022
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	606	Working alone	Holly Adams	Physical injury or illness due to lack of detection or response during incident or emergency situations. Encountered on GDS facilities, vehicles, customer premises or public places. - Work activities carried out alone (i.e. for a period of time with no direct contact or access to a co-worker) in field (e.g. meter work, locates, entering premises) or office (e.g. control room).	Employee injury during response	Work activities carried out alone (i.e. for a period of time with no direct contact or access to a co-worker) in field (e.g. meter work, locates, entering premises) or office (e.g. control room).	Lack of immediate response including inadequate provision of first aid leading to physical injury	Control Room Person Down Procedure* Emergency Response Plan and Training Lone Worker Program and Procedure** Equipment (vehicle GPS) Site Assessment Situational Awareness/Communication Work order communication Program (Adventex, Maximo)**	Prevent Prevent Prevent Mitigate Detect Prevent Prevent	Workforce safety	Health & Safety	3	5								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	607	New and inexperienced workers	Holly Adams	Physical injury and elevated stress due to lack of knowledge and experience in managing work activities including during incident or emergency situations.	Employee injury during response	Office and field work i.e. various activities	Physical injury due to lack of immediate and or appropriate response due to inability or unfamiliarity to workplace scenarios	New and Young Worker Awareness Training Technical Learning Competency Program STO Mentor and Training Program Site Assessment** Situational Awareness**	Prevent Prevent Prevent Detect Prevent	Workforce safety	Health & Safety	3	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	608	Falling from heights (> 3m)	Holly Adams	Working at heights where physical injury can result from a fall. Encountered on GDS premises including offices, stations or customer and public premises.	Slips trips and falls (excludes stairs)	Working at heights (e.g. from ladders, PELPs, roofs, climbing towers, heavy equipment, large vehicles, bridges), working around unprotected openings (e.g.. excavations, new construction), working above or near operating equipment, fixed platforms, and working from scaffold	Falling while working at height or vertical distance that can cause a physical injury .	Equipment Training (STO) Working at Heights Program and Training** Tool and Inspection Program Personal Protective Equipment Program Site Assessment** Situational Awareness/Communications**	Prevent Prevent Prevent Mitigate Prevent Prevent	Workforce safety	Health & Safety	3	5								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	609	Slips, Trips and Falls from outdoors at same level, elevated levels (i.e. < 3m), or inclined surfaces with varying terrain or working environment conditions	Holly Adams	Physical Injury can occur when a worker falls due to loss of traction of their shoes (i.e. slip) on the walking surface or if a worker loses their balance (i.e. trip) after an inadvertent contact with a fixed or moveable object (i.e. uneven or curved surfaces, encroached fixtures or equipment). Encountered on GDS premises including offices, stations or customer and public premises.	Slips trips and falls (excludes stairs)	Walking outdoors under various seasonal conditions (e.g. snow, ice, mud), on multiple terrains (e.g. uneven surfaces, loose terrain, slippery work surfaces, contact with surface debris), climbing up or down different surface levels (i.e. stairs, steps, curb) including inclined surfaces and working environments (e.g. congested, restricted/tight space).	Slips and trips result in physical injury due to the force of impact of the worker with the walking surface or stress or strain on parts of the body	Field Ergonomics Program and Training * Working at Height Program (Fall Protection) and Training** Basic Health and Safety Awareness Training Personal Protective Equipment Site Assessment** Situational Awareness/Communications**	Prevent Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	6	4			Monthly Safety Package topic Nov-March Tailgate talk created with focus on vehicle preparedness kits New risk description proposed to target the appropriate hazard and consequence Will develop targeted updated mitigation plan based on new risk description	Marc Lieder	2022	Proposed timeline changed from 2021 to 2022 on 06/22/2022 Q4 2022 Update: - Tactics complete – 2023 workshop planned as follow-up to 2022 annual risk review		MP-04: Health & Safety	2023-01-31
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	610	Slips, trips, or Falls while indoors at same level or elevated levels (i.e. < 3m) with various flooring types, or congested working environments	Holly Adams	Falls from elevated levels (<3m) (i.e. stairs, steps, curbs, vehicles) can cause physical injury as a result of the condition of the steps/stairs, lack of support (railing), or inattention to the task.. Encountered on GDS premises including offices, stations or customer and public premises.	Slips trips and falls (excludes stairs)	Walking indoors on various flooring types (e.g. carpet, tile), climbing up or down different surface levels (i.e. stairs, steps, elevators) including inclined surfaces (e.g. ramps).	Physical injury can occur due to slips and trips on elevated levels < 3 m.	Working at Height Program (Fall Protection) and Training** Basic Health and Safety Awareness Training Personal Protective Equipment Site Assessment** Situational Awareness/Communications** JHSC Inspections **	Prevent Prevent Mitigate Detect Prevent Detect	Workforce safety	Health & Safety	4	4								MP-04: Health & Safety	6/3/2021

First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version	Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard	Source	Consequences	Controls	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	611	Forcible contact with equipment, tools, furniture, objects, etc.	Holly Adams	Physical injury caused by inadvertent contact while working with or near people or materials. Can occur in GDS facilities including offices, customer premises or public places.	Exposure to Musculoskeletal Risk Factors	General workplace activities where there is congestion, tight spaces or in close proximity of tools or materials with potential to contact or collide (e.g. walking into doors, colliding with co-workers in corridors)	Physical injury produced by forcible contact or impact between the injured person and another person, object or piece of equipment.	Facilities Management (Building and Fire Code) Program, including equipment (e.g. mirrors) JHSC Inspections Site Assessment** Situational Awareness**	Prevent Detect Detect Prevent	Workforce safety	Health & Safety	4	2								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	612	Struck by dropped or falling objects (including pinched or crushed)	Holly Adams	Physical injury caused by worker contact with materials, tools or equipment that have fallen from point of origin i.e. including getting pinned between material and stationary object. Can occur in GDS facilities, customer premises or public places.	Dropped or falling objects	Working in or near elevated general work activities including manual material handling (e.g. meter set, pipe racks, warehouse shelving) or mechanical material handling (e.g. loading/unloading trailers, trucks, other vehicles, excavating), overhead work (e.g. within an excavation or trench, near loose soil), under a vehicle, under a scaffold.	Physical injury can occur from material, tool or equipment falling from an elevation to a lower level and making forcible contact with a worker.	Manual material handling training Drop zone procedures/barriers (STO)* Hoisting and Rigging, Hiab Equipment Inspection Hoisting and Rigging Training* Hiab Training * Excavation and Shoring Procedure and Training** Facilities Management, shelving/racking standard Personal Protective Equipment Site Assessment** Situational Awareness/Communication**	Prevent Prevent Detect Prevent Prevent Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	3	5								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	613	Struck by flying objects	Holly Adams	Physical injury caused by worker contact with a particle, material or object that has been thrown, hurled, projected or propelled from its point of origin. Can occur in GDS facilities, customer premises or public places.	Exposure to Mechanical Energy	Working with or near equipment and tools under pressure or applied force. Working with or in vicinity of equipment that ejects material, including airborne particles (e.g. grinders, chain saws, drills, etc.) or projectiles (e.g. valve cores, tubing, debris caused by blowing gas), and tool kick-back.	Physical injury can occur when a tool or piece of material separates from a tool, machine or equipment, forcibly striking a worker.	Manual material handling training Tool and Inspection Program Specific Tool/Equipment Training e.g. chainsaw Personal Protective Equipment including eyewash Site Assessment** Situational Awareness/Communication**	Prevent Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	6	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	614	Struck by moving or swinging objects	Holly Adams	Physical injury caused by worker contact with materials or equipment where worker is located within the range of the equipment. Encountered on GDS premises including stations or customer and public premises.	Exposure to Mechanical Energy	Directing, working in or near equipment (i.e. mobile work), used for mechanical handling (e.g. loading/ unloading trailers, trucks, dump trucks, backhoes, or other vehicles) and lifting tasks (e.g. crane, hoist, boom truck, backhoe, side boom, forklifts) including loose soil i.e. trenching or excavating	Physical injury occurs when materials or equipment, including parts of the equipment, being lifted or maneuvered make contact with worker	Hoisting and Rigging Training Drop zone procedures/barriers (STO)* Hoisting and Rigging, Hiab Equipment Hoisting and Rigging and Training* Hiab Training * Personal Protective Equipment Visitor Site Orientation Site Assessment**	Prevent Prevent Prevent Prevent Prevent Mitigate Prevent Detect	Workforce safety	Health & Safety	6	4			New risk description proposed for GDS Risk Register to target mitigation plan appropriately Will assess in 2021 to determine if additional plan is required	E.Rodrigues	2022	Proposed timeline changed from 2021 to 2022 on 06/22/2022 Q4 2022 Update: - Tactics complete – 2023 workshop planned as follow-up to 2022 annual risk review Treatment plan complete but will remain on register - 5/2/2023		MP-04: Health & Safety	2023-05-02
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	615	Operating vehicle off road (i.e. driving)	Holly Adams	Physical injury from driving or riding a vehicle on unsurfaced roads or tracks (i.e. Materials such as sand, gravel, riverbeds, mud, snow, rocks, and other natural terrain)	Exposure to Mechanical Energy	Driving off road vehicles (e.g. ATV, lawnmowers, snowmobiles) to conduct tasks (e.g. right of way inspections, remote site commute, remote site field work) on varying surfaces	Physical injury including strains due to driving off road conditions	Driver Safety Program including in cab evaluations and awareness training All Terrain Vehicle Training Tool and Equipment Maintenance Program Personal Protective Equipment Site Assessment ** Situational Awareness/Communication**	Prevent Prevent Prevent Mitigate Detect Prevent	Workforce safety	Health & Safety	3	3								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	616	Operating vehicle - Maneuvering (e.g. parking)	Holly Adams	Elevated stress related to manipulating a vehicle (i.e. stopping, disengaging, redirecting, reversing) in order to maneuver in restrictive space (i.e. parking lots, roadside, driveway). Encountered on GDS premises including parking lots, stations or customer and public premises.	Operator errors	Maneuvering vehicles (i.e. driving) to be in close proximity and accessible for work activity, maneuvering vehicles in restricted space.	Stress related occupational illness can occur from anxiety related to vehicle operation in restrictive or congested spaces.	Driver Safety Program including in cab evaluations and awareness training Spotter Training Vehicle Design Standards** Fleet Preventative Maintenance Program* Site Orientation (STO) Vehicle Rental Program* Life Saving Rules Workplace Observations* Site Assessment ** Situational Awareness/Communication** Winter Travel Paths and Snow Removal Plans (STO)*	Prevent Prevent Prevent Prevent Prevent Prevent Prevent Prevent Detect Prevent Prevent	Workforce safety	Health & Safety	7	1								MP-04: Health & Safety	6/3/2021
3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL	617	Driving - general	Holly Adams	Driving under normal conditions, in inclement weather, congested or in unfamiliar vehicle causes stress, fatigue and can cause physical injury if involved in a vehicular incident. Encountered on GDS premises customer and public roadways.	Worker fatigue	Operating motor vehicles on roadways under varying conditions of weather and traffic. Includes driving while towing equipment and operating CVOR vehicles, rental vehicles and personal vehicles for work activity	Vehicular incidents where physical injury or stress occurs due to contact with other vehicles, pedestrians, wildlife or stationary objects.	Driver Safety Program including in cab evaluations and awareness training Winter Driving Training Vehicle Design Standards** (e.g. GPS) Fleet Preventative Maintenance Program* Site Orientation (STO) CVOR Program** Vehicle Rental Program* Lone Worker Program** Life Saving Rules Workplace Observations* Situational Awareness/Communication**	Prevent Prevent Detect Prevent Prevent Prevent Prevent Prevent Prevent Prevent Prevent	Workforce safety	Health & Safety	5	5			Mitigation plan completed New risk description proposed to target the appropriate hazard and consequence Will develop targeted mitigation plan based on new risk description	E.Rodrigues	2022	Proposed timeline changed from 2021 to 2022 on 06/22/2022 Q4 2022 Update: - Tactics complete – 2023 workshop planned as follow-up to 2022 annual risk review		MP-04: Health & Safety	2023-01-31
2. Pipeline transportation of natural gas	2.3. Pipeline	2.3.3. Pipeline Aggregate	2. Ontario Transportation											New 2021	EGI	FINAL	619	High pressure Entering the Payne Pipeline Exceeding 1000 psi	Hillary Thompson	High pressure entering the Payne pipeline exceeding 1000 psi from the Corunna or Ladysmith pipelines causing exceedance of MAWP.	Operate beyond allowable limits	High pressure entering the Payne pipeline exceeding 1000 psi from the Corunna or Ladysmith pipelines	Exceedance of MAWP of the Payne pipeline. Engineering assessment confirms there is damage to pipeline. (This is a WORST credible CASE.)	-Valve S3-00-121 will close based on downstream MAWP. -Valve S3-00-119 has OPP that will close based on 103% of MOP. -Valve S3-00-123 will close based on downstream MAWP. -Valve S3-00-119 has OPP that will close based on 103% of MOP.	Prevent Prevent Prevent Prevent	Operational reliability	Operational	1	7							Reputational: Med L1 C7 Environmental: Low L1 C4 Financial: Low L1 C4 H&S: Low L1 C5	MP-01: Asset	6/25/2021
1. Natural gas distr	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.14. EGI Aggregate										52	LGD	FINAL	620	Non-Vital Pipeline - 1st and 2nd Party Damages	Michael McGivery	Underground non-vital pipeline could be damaged due to 1st and 2nd party excavation activities. This could impair condition of assets and lead to potential release of natural gas, subsequently increase in green house gas emission, potential H&S impact to workers and service disruption **Context :** Risk Evaluation Approach - Consequence ranking is based on single event. Likelihood ranking of the event was based on the entire population of non-vital pipeline system taking into consideration of existing controls and other factors leading to the specific consequence. For the combined franchise areas, there are approximately 10 to 20 damages per year. NOTE: Sewer Crossbore and Compression Coupling risks are addressed as separate risk entries in the risk register. Hence, they are excluded from this evaluation.	2nd party damage	- Inappropriate methods used to excavation in the vicinity of natural gas facilities could increase potential of pipe damage. - Locate Service Provider (LSP) could have difficulty to access current records in timely manner. In ability to access records would delay issuance of locate, subsequently excavator may conduct work without locate. There is also potential for LSP to interpret records incorrectly. - Mains or services are installed during the valid period of a locate (60 days) and contractor is not aware of them, conduct construction activities around the new pipes, subsequently damage the pipe - Ontario One Call could fail to / inaccurately / delay in process locate requests to the Locate Service Provider which subsequently lead to lost calls, failure to / inaccurately to / delay to process tickets. This could potentially lead to excavation damages to underground assets and customer dissatisfaction. **NOTE on Hazard / potential hazard** 1st Party damages also applies to this risk	Gas release, venting to atmosphere : Release of natural gas, subsequently increase in green house gas emission and potential interruption of services, with remote chance of flammable gas event leading to H&S impact NOTE : Risk driver is reputational risk with more weight on regulatory impact than media coverage	**Engineering Design** 1) Minimum DOC requirement 2) Excess Flow Valve installed at service connection (for new services) **Operation Standard / Manuals** 1) ST-1B-A14C-36FF Depth of Cover Operating Standard, ST-17-A1C8-8CE9 Pipeline Markers Operating Standard (For some non-vital mains, especially those in remote locations) 2) Emergency Processes in various manuals - C&M, CS&C, EH&S and ERP (Emergency Response Plan) **MP-07** Manuals, these are used by external parties : 1) Third Party Requirements in the Vicinity of Natural Gas Pipelines Processes (Note: Currently operating with formal document integration in-development), these are GDS facing processes: 2) Locate Request - Public ROW Process (Sticker locates), Locator Support Process, Records Support Process, DP Quality Management Process 3) Competency Management Process, Crossing and Encroachment Authorization Process, Public Awareness Process **MP-03** Notification to TSSA through Spills Action Center (SAC) **Public Affairs & Ombudsman office** Standard media protocols	**Eng. Design** 1) Prevent 2) Mitigate **Opt Std / Manuals** 1) Prevent 2) Mitigate **MP-07** 1) Prevent 2) Prevent 3) Prevent **MP-03** Detect / Mitigate **PA&O office** Mitigate	Workforce safety	Reputational	7	3			A series of initiatives which are enhancements and expansions of existing controls focused on preventing damages	Michael Abate	N/A	Ongoing monitoring of existing controls and associated metrics to determine adjustments as appropriate (Q4 2022) Q4 Updates: - reverted timeline to N/A	- Financial (Based on cost for repair - gas cost, labor, material, equipment and resource time): L7C1 Medium - Health & Safety (Ranking based on employee injury) : L5C3 Medium - Environment (Based on damages to surface gravel or soil within an Enbridge facility; able to be remediated by trained personnel quickly and effectively) : L7C2 Medium Operational (Based on outage and resource diversion. Expected a couple of crews would be required to make safe) : L7C2 Medium	MP-07: Damage Prevention	2023-01-31
3. Aggregate			3. Aggregate											33	LGD	FINAL	621	Vital Pipeline - 1st and 2nd Party Damages	Michael McGivery	Underground vital mains could be damaged due to 1st and 2nd parties excavation activities. This could impair condition of assets and lead to potential release of natural gas, subsequently increase in green house gas emission, potential H&S impact to workers and service disruption **Context :** Risk Evaluation Approach - Consequence ranking is based on single event. Likelihood ranking of the event was based on the entire population of vital pipeline system taking into consideration of existing controls and other factors leading to the specific consequence. NOTE: Sewer Crossbore and Compression Coupling risks are addressed as separate risk entries in the risk register. Hence, they are excluded from this evaluation.	2nd party damage	- Inappropriate methods used to excavation in the vicinity of natural gas facilities could increase potential of pipe damage. - Locate Service Provider (LSP) could have difficulty to access current records in timely manner. In ability to access records would delay issuance of locate, subsequently excavator may conduct work without locate. There is also potential for LSP to interpret records incorrectly. - Mains or services are installed during the valid period of a locate (60 days) and contractor is not aware of them, conduct construction activities around the new pipes, subsequently damage the pipe - Ontario One Call could fail to / inaccurately / delay in process locate requests to the Locate Service Provider which subsequently lead to lost calls, failure to / inaccurately to / delay to process tickets. This could potentially lead to excavation damages to underground assets and customer dissatisfaction.	Gas release, venting to atmosphere : Release of natural gas, subsequently increase in green house gas emission and potential interruption of services, with remote chance of flammable gas event leading to H&S impact NOTE: There are multiple risk drivers : Financial, H&S to worker, Operational and Reputational Impacts	**Engineering Design** 1) Minimum DOC requirement 2) Excess Flow Valve installed at service connection (for new services) 3) ST-1C-A2AC-3AF4 HCA and Class Location Design Standard **Operation Standard / Manuals** 1) ST-19-FB80-F526 Class Location Operating Standard 2) ST-1B-A14C-36FF Depth of Cover Operating Standard, ST-17-A1C8-8CE9 Pipeline Markers Operating Standard (For some non-vital mains, especially those in remote locations) 3) Emergency Processes in various manuals - C&M, CS&C, EH&S and ERP (Emergency Response Plan) **MP-07** Manuals (These are use for external parties): 1) Third Party Requirements in the Vicinity of Natural Gas Pipelines, CGA Best Practices Guides for Damage Prevention & Safety Processes (Currently operating with formal document integration in-development), these are GDS facing processes: 2) Locate Request - Public ROW Process (Sticker locates), Locator Support Process, Records Support Process, DP Quality Management Process 3) Pipeline Patrol Process 4) Competency Management Process, Crossing and Encroachment Authorization Process (Permit applies to CER assets and some STO assets), Public Awareness Process 5) Land Use and Ownership Monitoring Process (Tie to HCA assets, asset types of buildings and who own them and asset types of risks) **MP-03** Notification to TSSA through Spills Action Center (SAC) **Public Affairs & Ombudsman office** Standard media protocols	**Eng. Design** 1) Prevent 2) Mitigate 3) Prevent / Detect **Opt Std / Manuals** 1) Prevent / Detect 2) Prevent 3) Mitigate **MP-07** 1) Prevent 2) Prevent 3) Prevent / Detect 4) Prevent 5) Detect **MP-03** Detect / Mitigate **PA&O office** Mitigate	Workforce safety	Health & Safety	3	6							- Financial (Based on repair cost of an average damage): L6C3 Medium - Environment (Ranking based on estimated area being impacted following a potential damage) : L3C3 Low Operational (Based on outage and resource diversion. Expected a couple of crews would be required to make safe) : L3C5 Medium - Regulatory (Based on evacuation and regulatory impact - e.g. CER) : L3C4 Medium	MP-07: Damage Prevention	2021-06-15
3. Aggregate			3. Aggregate											New 2021	EGI	FINAL	622	Incomplete Locates for Work in the Vicinity of Assets for Multiple Enbridge Business Units (Between LP and GDS) and GDS Business Functions (LED Storage, LUG Storage, DO)	Michael McGivery	There are tendency to have incomplete locates for work (but not exclusively) occur near GDS storage systems, gate stations, and pipelines within private ROWs where Multiple Enbridge Business Units (Between LP and GDS) and GDS Business Functions (LED Storage, LUG Storage, DO), leading to potential damage on GDS assets. **Context** Risk Evaluation Approach - Consequence ranking is based on single event. Likelihood ranking of the event was based on the selected population of assets (Transmission / Vital mains / DO mains) which are in the vicinity of assets from other Enbridge business units (Between LP and GDS) and GDS functions (LED Storage, LUG Storage, DO) taking into consideration of existing controls and other factors leading to the specific consequence. NOTE: All man made ground disturbance is included in this risk	3rd party damage	Potential for damage on Gas Distribution & Storage business unit assets in the vicinity of assets from other Enbridge business units by a third party who places a request for utility locates but does not understand that separate locates must be completed for each business unit. - Public unfamiliar with locate process - Confusion that Enbridge has many different types of assets NOTE: An instance has occurred where an excavator was working in the vicinity of vital asset (STO asset in the associated instance) and non-vital assets while using an ALA instead of a traditional locate The concern is really with contractors or landowners (e.g. farmers) who are not familiar with the locate process that may get confused that a "clear" locate applies to all BUs assets. Storage assets runs through southwest / southeast regions and GTA west (Parkway west all the way to Albion Gate, paralleling Hwy 7) region surrounded by DO assets, Niagara area where the Crowland facility is, the other locations are typically around gate stations (particularly where custody switches from STO to Gas Distribution).	Gas release, venting to atmosphere : Release of natural gas, subsequently increase in green house gas emission and potential interruption of services, with remote chance of flammable gas event leading to H&S impact NOTE: There are two risk drivers : H&S to public (Ranking based on potential single fatality in case of line strike leading to fire / explosion))& Operational (see additional rankings for more details)	Engineering Design 1) Minimum DOC requirement 2) Excess Flow Valve installed at service connection (for new services) 3) ST-1C-A2AC-3AF4 HCA and Class Location Design Standard Operation Standard / Manuals 1) ST-19-FB80-F526 Class Location Operating Standard 2) ST-1B-A14C-36FF Depth of Cover Operating Standard, ST-17-A1C8-8CE9 Pipeline Markers Operating Standard (For some non-vital mains, especially those in remote locations) 3) Emergency Processes in various manuals - C&M, CS&C, EH&S and ERP (Emergency Response Plan) MP-07 Manuals (These are use for external parties): 1) Third Party Requirements in the Vicinity of Natural Gas Pipelines, CGA Best Practices Guides for Damage Prevention & Safety Processes (Currently operating with formal document integration in-development), these are GDS facing processes: 2) Locate Request - Public ROW Process (Sticker locates), Locator Support Process, Records Support Process, DP Quality Management Process 3) Pipeline Patrol Process 4) Competency Management Process, Crossing and Encroachment Authorization Process (Permit applies to CER assets and some STO assets), Public Awareness Process 5) Land Use and Ownership Monitoring Process (Tie to HCA assets, asset types of buildings and who own them and asset types of risks) 6) Third Party Observation Process (Apply to all Transmission / Vital Mains and discretionary for DO assets) MP-03 Notification to TSSA through Spills Action Center (SAC) Public Affairs & Ombudsman office Standard media protocols	Eng. Design 1) Prevent 2) Mitigate 3) Prevent / Detect Opt Std / Manuals 1) Prevent / Detect 2) Prevent 3) Mitigate MP-07 1) Prevent 2) Prevent 3) Prevent / Detect 4) Prevent 5) Detect 6) Prevent MP-03 Detect / Mitigate PA&O office Mitigate	Public safety	Health & Safety	4	5							- Financial (Ranking based on estimated remediation cost associated with a potential damage of a transmission line which is the worst case (e.g. between Dawn and Parkway)) L4C4 Medium - Environmental (Ranking based on estimated area being impacted following a potential damage) L4C3 Medium - Operational (Ranking based on potential damage on a transmission line leading to disruption of transportation customers. In worst case, could take 3 months to resume services) L4C5 Medium - Reputational (Based on media coverage. Local media coverage is referring to major news outlet such as CP24) L4C4 Medium	MP-07: Damage Prevention	2021-06-28
3. Aggregate			3. Aggregate											New 2021	EGI	FINAL	623	Legacy Contamination associated with Former Manufactured Gas plants - Potential legal concern with selling contaminated sites	Jennifer Burnham	Legacy contamination associated with former manufactured gas plant which could lead potential legal concern if it is inadvertently sold (environmental condition is not considered or disclosed to buyer).	Contaminated Soil and Water	Legacy MGP sites are known to have had contaminating activities as part of the operations	Potential legal concern with selling contaminated sites (environmental condition is not considered or disclosed to buyer). NOTE: Financial Impact : Legal cost and potential cost to rectify the issue	- List of contaminated sites - Legacy EGD disposal check list - Contaminated Sites Working Group	Detect Prevent / Detect Prevent / Detect	Environmental	Financial	3	4			Develop site list and risk rank sites. - Complete site investigation at selected sites (Completed) - Contaminated site list development (Completed) - Develop risk evaluation process for contaminated site list (In draft) - Risk assess contaminated sites - develop priority action plan - Integrate the list of contaminated sites with LUG list of contaminated sites Apply risk based decision principle to prioritize resources for managing contaminated sites	Erin Nolan	Q4 2023	Treatment plan changed from 2020 - 2022 07/19/2022 Q4 2022 Update -Continue environmental site investigations / remedial options for identified sites (Emma Street) -Completed annual groundwater monitoring at Brantford (Q4) -Continued work with REWS to develop reuse strategies for Brantford property -Station B REWS redevelopment in progress (and applicable soil management processes) Timeline changed from 2022 to Q4 2023. Management program goal for 2023 is to work on a contamination site plan - 5/2/2023	One RR only	MP-03: Environmental	2023-05-02
1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	2. Ontario Transportation	1.11. Transmission East	1.10.1. EGI Aggregate	New 2021	LGD							New 2021	EGI	FINAL	624	Glycol Spills from Station Boiler Heating Systems	Rob Sterling	Glycol Spills from station boiler heating system equipment or piping inside building and outside on station property causing potential public H&S risk if significant glycol spill impacts drinking water wells off site.	Spills of pollutant into the natural environment	1. Possible glycol leaks from heating system equipment or piping inside building (indoor equipment typically includes boilers, pressure relief, glycol recirculation pumps, air extractors, instruments/controls, gauges, expansion tanks) 2. Possible leaks from heating system equipment or piping located outside on station property (outdoor equipment typically includes the heat exchanger, overpressure burst disk, air extractors, instruments/controls, gauges, and atmospheric glycol expansion tank)	1. Glycol leak inside a building may be contained unless it is a large volume release with potential to overflow and spill outside the boiler building. Buildings may not be sealed properly or secondary containment in building may not be adequately designed to contain glycol spills (just minor leaks). Glycol may release outside building resulting in environmental cleanup cost. Risk may be impacted by station location/proximity to waterways, drinking water wells, or potential glycol contamination from heavy metals/arsenic. Potential environmental, reputational, and financial risk for cleanup costs. Potential public H&S risk if significant glycol spill impacts drinking water wells off site. 2. Outdoor glycol leak from piping or equipment to grade resulting in environmental cleanup cost. Risk may be impacted by station location/proximity to waterways, drinking water wells, or potential glycol contamination from heavy metals/arsenic. Potential environmental, reputational, and financial risk for cleanup costs. Potential public H&S risk if significant glycol spill impacts drinking water wells off site.	-Spill management program. Some inconsistency between legacy businesses on spill kit (on site kits vs in trucks). Currently in progress of integration -Flow switch and low water cut off are not tied to SCADA / Gas Control (glycol leak detection controls and alarms may be inconsistent across stations). Station low temperature or low pressure alarms are tied to SCADA / Gas Control with operator action -Some heating equipment at some stations has secondary containment regarding glycol relief devices discharging to a tank -Routine scheduled station visits, maintenance, and monitoring	Mitigate Prevent Prevent Detect	Public safety	Health & Safety	4	4			1. Consider implementing a consistent secondary containment design for existing stations to mitigate potential glycol spills from station heating systems inside buildings (i.e. bring old stations up to current design practice). 2. Consider developing consistent station inspection frequency to mitigate the chance of a glycol leak progressing into a glycol spill with the potential of going outside a boiler building or off site. Currently the schedule is monthly visits consider increasing visit frequency. Consider best practices to monitor heating system condition for glycol leak detection. 3. Consider including leak detection instrumentation and controls in the SCADA system to provide an early warning for potential glycol leaks 4. Consider implementing a consistent secondary containment design for existing stations that have glycol relief devices discharging to grade (i.e. bring old stations up to current design practice). 5. Consider how to inspect, monitor, or prioritize replacing glycol piping that is not readily accessible for visual inspection. This issue is visual inspections may not be able to identify or monitor the condition of buried glycol piping or piping under cladding / insulation.	1. Rob Sterling 2. James Whitnall 3. Ryan Boyd 4. Rob Sterling 5. Rob Sterling Kevin Bowers Ryan Boyd		The risk ranking is considered a worst case consequence based on assumed station location / proximity to waterway drinking water wells, or potential glycol contamination from heavy metals/arsenic. When ranking future individual station projects for the asset plan these factors would need to be considered on a case by case basis per station to assess appropriate consequence. Likelihood is based on the average chance of an accidental leak within the total station heating system population (roughly over 100 stations but less than 1000 in total population). Risk is considered to apply to distribution and STO station facilities with boiler heating systems installed pre 2015. 03/27/2023 AMH - Updated Risk Owner from A. Nossair to R. Sterling	Financial L4 C3 Medium Environmental L4 C4 Medium Reputational L4 C4 Medium	MP-05: Integrity	12/6/2021
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	2. Ontario Transportation	1.14. EGI Aggregate	1.10.1. EGI Aggregate									New 2021	EGI	FINAL	627	Modern Plastic-PE Mains	Carrie Cook	Inadvertent deviation from procedure due to a number of reasons.	Construction defect	Inadvertent deviation from procedure due to a number of reasons.	Possible cold fusion (service fitting does not properly adhere to the main) leading to potential latent failure gas release. Gas release can potentially migrate, ignite, resulting in a fire with potential public fatalities at a single-family home, multi unit building (MUB), or high density commercial	-Leak survey -Emergency response procedures (MP-02) -PE Fusion Manual - C&M Manual procedures -Gas is odourised for leak detection -PSI or Technical Field Specialists may be on site to perform QA check -Focused audit of calibration -Operator qualification with annual competency review	Detect Mitigate Mitigate/Prevent Mitigate Mitigate Prevent	Operational reliability	Health & Safety	2	6			1. Consider calibration requirements of pressure gauges to help ensure correct pressure is applied to avoid potential cold fusion latent failures. Consider the upper and lower limits of allowable calibration of gauges. Ongoing as per procedure integration initiative. 2. Review the ASTM requirements for pressure application throughout the heat application cycle. Ongoing as per procedure integration initiative. 3. Consider daily maintenance requirements of SAT and gauge to help ensure correct pressure is applied to avoid potential cold fusion latent failures. Ongoing as per procedure integration initiative. 4. Consider providing technicians with a higher accuracy, additional pressure gauge in order to confirm fusion tools are within specification (the same hydraulic pressure gauge as the auditors). Consider training requirements to use new gauge. 5. Review allowable fitting design regarding pipe wall thickness and potential gap between fitting and pipe before fusion. The issue is an investigation completed in 2018 revealed that thinner walled PE pipes had a higher rate of failure and a research report identified that the larger the gap between fitting and pipe the greater the chance of blowout failure. 6. Consider temperature calibration requirements for fusion irons. The issue is the temperature measurement may not be consistent across the fusion iron. Another issue is the temperature measurement may occur on the heating block instead of the face of the tool that would be in contact with the pipe potentially resulting in inconsistent temperature readings (could potentially occur due to build up of material on tool or one defective coil out of two). Review the time between calibrations. 7. Consider adding more prescriptive maintenance and daily checks for PE fusion tools regarding missing or loose bolts, bent alignment pins, etc. in the procedures. 8. Review if an additional redundant QA sign off is a worthwhile additional risk control for PE fusions after the other risk treatment plans are implemented. Consider as a continuous improvement idea. 9. Consider if electro fusions can replace heat fusions to reduce the chance of failure. An electro fusion only pilot study was started in the Eastern Region (Ottawa). Follow up on the results of that pilot. 10. Review approved peeler tools. One potential issue is using a flat peeler on around pipe since it could lead to changing the shape of the pipe or removing too much material. Newer tools go around the pipe circumference and are easier to use correctly/scrape the correct amount. Would be included in the procedure integration. 11. Consider including the engineering memo into procedure regarding keeping PE pipe in shade before fusions to limit potential PE fusion blowouts due to high temperature issues 12. Review how the technician is supposed to correctly time PE fusions. A potential concern is lone worker fusions require the one technician to use both hands for other tasks and still expected to correctly time actions. *15. Consider evaluation of alternative fitting manufactures to potentially lower the cost of joining contaminated PE pipe. Not possible due to limited products available compliant with CSA. *16. Consider conducting an integrity study to identify the source of hydrocarbon contamination in PE pipe. Determine how long it would take for contaminated pipe to self heal once contamination source is eliminated to potentially allow for future use of PE fusions in order to lower incremental operating costs. *17. Consider updating procedures and direction on potential PE pipe contamination in other regions and other PE vintages. Currently issue is detected in mainly SW Region - Windsor and London. Currently issue is though to apply to PE vintages prior to 2000. 18. Evaluate adding an attribute in MAXIMO to specify where pipe was installed by drilling to help identify assets where drilling installation practice could potentially contribute to integrity issues in the long term.	1-5. Maurice Sardari 6. Maurice Sardari & Jo Milo 7. Maurice Sardari 8. Fred Butrico 9. Maurice Sardari & Fred Butrico 10-12. Maurice Sardari 15. Maurice Sardari 16. Fred Butrico 17. TBD 18. Fred Butrico		Refer to Hydrocarbon Contamination (ID 303), that issue may also be applicable to Modern Plastic PE Mains	H&S Medium L1 C6, L2 C6, Low L1 C5	MP-05: Integrity	8/19/2021
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.10.1. EGI Aggregate									New 2021	EGI	FINAL	628	Vintage Steel Mains	Tara Kuuskman	Potential coating failure. Below ground corrosion and metal loss on distribution pipe body leading to pinhole leak.	Corrosion external	Below ground corrosion and metal loss. Potential coating failure (Disbondment or holiday) or vintage bare pipe leading to potential depletion of anode over time.	Corrosion on distribution pipe body (distribution pipe considered < 30% SMYS). Corrosion leads to a pinhole leak that can typically be detected and remediated with repairs before further consequence	-Leak Survey -Tracking of incidents through encompass with incident investigation procedures -Damage prevention program and one call prevents Damage to pipeline coating / latent Damage -Pipe replacement projects identified for Asset Plan based on tacit knowledge, AHR, DIMP risk model, etc. -Emergency response procedures -Leak repair procedures -Gas is odourised for detection -Corrosion prevention program - cathodic protection, monitoring and maintenance of cathodic protection systems -Pipeline coating prevents initiation of corrosion	Detect Mitigate Mitigate/Prevent Mitigate Mitigate Mitigate Detect Prevent Prevent	Operational reliability	Financial	3	6			1. Proactive vintage steel replacement program planned for 2027	Fred Butrico	2027	1. Vintage steel up to ~NPS 6 and 60 psig is considered to be replaced with modern PE. The residual ranking is assumed to be related to potential pipe defect from manufacturer and as a result low risk based on Modern PE ranking. 2. Larger diameter vintage steel replaced with modern steel also considered to have a low residual risk for corrosion hazards. Risk Owner updated from A.S on August 1, 2023	Financial Medium L5 C2	MP-05: Integrity	2023-08-01
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.10.1. EGI Aggregate									New 2021	EGI	FINAL	629	Legacy Services Without an EFV	Tracey Teed Martin	Legacy design practice did not specify EFV requirement. This entry cover services to customer without an EFV.	3rd party damage	1. Vehicle damage to above grade piping with winglock valve 2. 3rd party damage that causes a severed service outside the customer premise	1. IP Leak outside venting to atmosphere with potential to migrate through a building opening, with potential to build up to flammable concentrations, reaching an ignition source and causing a building explosion with multiple fatalities at MUB 2. Leak from severed service worst case chance gas could migrate into a nearby multi-unit building with potential to ignite resulting in a possible building explosion and public fatalities	1. Locate procedures & call before you dig. Some locations with below grade entry have a warning sign to alert public to acquire locates before excavation. 2. Gas is odourised for leak detection 3. Building ventilation may limit gas build-up to flammable limits 4. Emergency call procedures i.e. customer advised to open windows or evacuate immediately etc. depending on situation 5. Emergency response procedures 6. Leak survey may detect latent damages that eventually develop into a leak sometime after initial line strike	Prevent Detect Mitigate Prevent Prevent Detect	Public safety	Health & Safety	2	7			1. Consider relocating indoor regulators into an external regulator room (ERR) or relocate outdoors if possible, to do so. Some locations may not be immediately possible to relocate due to external factors not under the company's control, however over the long-term relocation may be possible. Similar treatment plans were previously considered and initiated in both legacy parts of the business. 2. Consider retrofitting services without an excess flow valve (EFV) to include one. Alternatively if an EFV cannot be designed to function as intended for a service with an inside regulator, consider adding a "weak link" to service such as transition to PE and/or above grade shut off valve before building entry (alternative is not a consideration for service regulators located outside). Note that EFV are potentially limited in design due to customer demand and/or delivery pressure vs. flow set point limitations of EFVs i.e. not all service may be possible to design an EFV for. NOTE: Plan under development in 2021	Kirby Skinn-Jones	2021	Risk owner change from Mike Wagle to Tracey Teed martin - 06/20/2022 1. Note that reduced outflow after an EFV triggers means a leak will still occur but at a lower rate. Lower leak rates are less likely to reach flammable concentrations or may allow more time for self-evacuation. Based on SMA input, relocation of inside regulators is most likely the better risk treatment option however the matrix cannot differentiate frequencies lower than L1. 2. The company has a good history of observing the EFV functioning as intended and reducing the outflow from a leaking service after a damage. Treatment Owner changed to Kirby Skinn-Jones 2/8/2023	H&S Medium L2 C5, L2 C6	MP-01: Asset	2023-02-08
1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution	1.4. Toronto (Area 10)	1.4.1. 10 – Toronto										EGI	FINAL	630	Albion Gate Station	Neil MacNeil	Flow control valve malfunctions open/closed during winter/heating season leading to inefficient operation of downstream compressors.	Electrical/controls malfunction	Flow control valve FS4201D malfunctions open during winter / heating season (when valve operation is required to prevent TCPL taking more gas than intended from the EGD system)	Credible worst-case for fails open: valve failure during winter (approximately Nov 1 - March 31 / TCE contract dependent) leading to inefficient operation of upstream compressors. Worst case is expected to occur on a design day. Resulting in potential compressor failure (if compressors in Stonewall are required). Worst case depends on the failure requiring the valve being shut in for remainder of season until isolation can take place in the summer to implement repairs. The way the system is currently designed causes inability to isolate Flow control valve FS4201D in the winter. Past compressor failures have caused the compressor to be down for an entire year impacting deliverability. Compressor repairs could run into the millions of dollars based on past	-Redundancy in network and downstream flow alarm monitoring / intervention by gas control	Detect/Mitigate	Operational reliability	Financial	4	4			1. Identify the appropriate design for the control valve feeding TCPL Kings North that will meet our control, bypass, and maintenance requirements. Option 1: Cut in NPS24 Becker Control Valve ANSI 600 and required piping 2. Identify the appropriate design for the control valve feeding TCPL Kings North that will meet our control, bypass, and maintenance requirements. Option 2: Cut in NPS24 Becker Control Valve ANSI 600 and required piping + 2 upstream isolation valves on each run 3. Identify the appropriate design for the control valve feeding TCPL Kings North that will meet our control, bypass, and maintenance requirements. Cut in NPS24 Becker Control Valve ANSI 600 and required piping + upstream/downstream isolation valves on each run (QTY 4)		Jan-24	A failure of the control valve that would require maintenance is estimated to occur once in the operating lifetime of the facility or less depending on local operating conditions (debris, moisture, contaminants, etc. in gas) and the maintenance schedule (planning required maintenance in summer). 2. Multiple feeds into the GTA network may be able to prevent any customer loss however would require DOE to quantify. Most realistic risk is buying back gas further downstream (such as at Victoria Square GS). Buying back gas incurs additional cost. Costs for gas buy back could be incurred daily for as long as the valve remains failed and add up over remainder of heating season. CSS Project #:	Public H&S Low L5 C1 Worker H&S Low L5 C1 Environmental Low L5 C1 Reputational Low L5 C1 Operational Low L5 C1 Financial Low L5 C1	MP-01: Asset	7/4/2022
1. Natural gas distribution	1.1. Pipe	1.1.5. Pipe Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.10.1. EGI Aggregate									New 2021	EGI	FINAL	631	Vintage Plastic - Aldyl A Mains	Tara Kuuskman	Potential loss of containment due to PE degradation over time caused by inherent properties of PE material.	Degradation	PE degradation occurs over time due to the inherent properties of PE material and can potentially be influenced by the manufacturing process. AHR modelling suggests the life of Aldyl A is > 50 years (i.e. higher chance of slow crack growth leaks may be expected after this time). Thought to be the likelihood driver of potential leak risk.	Potential loss of containment due to a larger crack failure leak (typically occurs near a fused fitting, or influenced by rocky soil, increased ambient temperature, squeeze off location, or bend in pipe), leading to potential gas migration to building, potential build up to LFL, and potential ignition resulting in possible injury or fatality.	- Leak monitoring of known leaks until repairs are made - Leak survey to detect new leaks - increased surveys in areas where rocky soil and Aldyl A pipe is known - Gas is odourised for leak detection - Leak Repair procedures - Pipe clamps on squeeze offs to prevent leaks - Emergency Processes in various manuals - C&M, NO, CS&C, EH&S, CER and EPM (Emergency Procedure Manual) - AHR, DIMP risk model, and Asset Management Planning for pipe replacement projects. Project selection includes factors that impact failures (rocky soils, etc.)	Detect Detect Detect Prevent/Mitigate Prevent Prevent Prevent/Mitigate	Public safety	Health & Safety	3	6						Typically, Aldyl A was installed in suburban areas in GTA likely to have single family homes driving a 5 consequence. Ranking could be increased for pipe replacement projects in dense downtown cores. Northern Region may have some Aldyl A in downtown areas. For downtown areas the ranking could be justified as a 6 in those cases. This will have to be considered for value assessments in CSS on a case by case basis for pipe project location. The credible worst case is shown but does not apply to the entire population. Risk Owner updated from A.S on August 1, 2023	Public H&S Medium L2 C6	MP-05: Integrity	2023-08-01

Current ID	First L1 - Role	First L2 - Type	First L3 - Objects	Second L1 - Locations	Second L2 - Regions	Second L3 - Areas	L1 - Enterprise	L2 - Business Unit	L3 - Department	L4 - Dept. 2	L5 - Dept. 3	L1 - Reporting Segments	L2 - Segment	L3 - System	Legacy ID	Legacy	Version
632	2. Pipeline transportation of natural gas	1.2. Station	1.2.3. Station Aggregate	2. Ontario Transportation											New 2021	EGI	FINAL
633	3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL
634	3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2021		FINAL
635	3. Aggregate	1.5. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2022	EGI	FINAL
636	1. Natural gas distribution	1.2. Station	1.2.3. Station Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.9.1. Aggregate									New 2022	EGI	FINAL
637	2. Pipeline transportation of natural gas	2.2. Plant	2.2.3. LNG Facility	2. Ontario Transportation	1.1. Northern (Union Eastern, Northwest, & Northeast Districts)	1.1.6. Northern Aggregate									New 2022	EGI	FINAL
638	2. Pipeline transportation of natural gas	2.2. Plant	2.2.3. LNG Facility	2. Ontario Transportation	1.1. Northern (Union Eastern, Northwest, & Northeast Districts)	1.1.6. Northern Aggregate									New 2022	EGI	FINAL
639	2. Pipeline transportation of natural gas	2.2. Plant	2.2.3. LNG Facility	2. Ontario Transportation	1.1. Northern (Union Eastern, Northwest, & Northeast Districts)	1.1.6. Northern Aggregate									New 2022	EGI	FINAL
645	2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation	1.8. Storage	1.8.3. 70 – Storage											FINAL
646	1. Natural gas distribution	1.2. Station	1.2.2. Meter/Gate Station	1. Ontario Distribution	1.3. GTA West & Niagara (Areas 20, 50, & 80)	1.3.1. 20 – Mississauga											FINAL
648	3. Aggregate			3. Aggregate	1.14. EGI Aggregate	1.10.1. EGI Aggregate											
649	3. Aggregate			3. Aggregate	1.14. EGI Aggregate	1.10.1. EGI Aggregate											
650	3. Aggregate	2.6. Aggregate		3. Aggregate	1.9. Transmission West	1.9.1. Aggregate									New 2021	EGI	
653	2. Pipeline transportation of natural gas	2.2. Plant	2.2.1. Compression Facility	2. Ontario Transportation	1.14. EGI Aggregate	1.10.1. EGI Aggregate										EGI	FINAL
654	2. Pipeline transportation of natural gas	2.4. Storage	2.4.2. Wellhead	2. Ontario Transportation													
655	3. Aggregate	1.5. Aggregate	1.2.3. Station Aggregate	3. Aggregate	1.14. EGI Aggregate	1.9.1. Aggregate									New 2022	EGI	
656	1. Natural gas distribution	1.1. Pipe	1.1.1. Distribution Main	1. Ontario Distribution													
657	3. Aggregate	2.6. Aggregate		3. Aggregate	1.14. EGI Aggregate	1.10.1. EGI Aggregate											
662	1. Natural gas distribution	1.1. Pipe	1.1.1. Distribution Main	1. Ontario Distribution	1.1. Northern (Union Eastern, Northwest, & Northeast Districts)	1.1.6. Northern Aggregate										EGI	FINAL
663	1. Natural gas distribution	2.6. Aggregate	2.3.3. Pipeline Aggregate	1. Ontario Distribution	1.14. EGI Aggregate	1.10.1. EGI Aggregate										EGI	FINAL
664	1. Ontario Distribution	1.2. Southwest (Windsor/Chatham, Sarnia/London)	1.2.5. Southwest Aggregate														FINAL
665	2. Pipeline transportation of natural gas	2.2. Plant	2.2.3. LNG Facility	2. Ontario Transportation	1.1. Northern (Union Eastern, Northwest, & Northeast Districts)	1.1.6. Northern Aggregate									NEW 2023	EGI	FINAL
666	1. Natural gas distribution	1.1. Pipe	1.1.1. Distribution Main	1. Ontario Distribution	1.6. Eastern (Area 60, Legacy EGD & Gazifère)	1.6.1. 60 – Ottawa									NEW 2023	EGI	FINAL

Current ID	Title	Risk Owner	Description	Hazard/Potential Hazard	Source	Consequences
632	Dawn Carryover	Wes Armstrong	Carry over occurs from increased duty requirements and seasonal withdraw requirements. Tariffs increased due to annual year to year variation.	Operate beyond allowable limits	14.2 Usage based on seasonal withdrawal requirements increasing duty requirements and causing carry over. UG keeps growing with peak increasing for UG with cap implemented in 2024.	14.2.1 Annual year-to-year variation average but increasing trend in duty required and increasing tariffs (TCPL) possible.
633	Contact with animals (domestic and wild attacks)	Holly Adams	Animal encounter resulting in a physical injury. May occur while working outdoors or on customer sites both indoors and outdoors.	Employee injury during response	Performing work and coming into contact with animals	Physical injury due to animal Encounter
634	Contact with insects (e.g. bites, stings, bed bugs, ticks, etc.)	Holly Adams	Insect encounter resulting in an illness (reaction). May occur while working outdoors on customer or GDS sites.	Employee injury during response	Performing work and coming into contact with insects	Occupational illness or physical injury from Animal Encounter
635	Locate Delivery Capacity	Michael McGivery	Resource capacity impacting timely locate delivery placing EGI assets at an increased risk of third party damage.	Inspection deficiency	High attrition rates of locators (salary concerns, seasonal fluctuations). Increasing locate request volumes. Insufficient locate request intake by Ontario One Call. Increasing locate technical requirements	Non compliance of locates delivery might result in orders/notifications from Ontario One Call.
636	Stations with operator monitor pressure control that do not have main line filtration (double boot regulators)	Rob Sterling	Various type of debris in gas could potentially damage operator and monitor boots simultaneously leading to possible overpressure of downstream	Equipment malfunction	Construction debris, welding slag, pigging operations upstream, etc. going to a customer station or one way feed station (small network), and LP stations	Debris damages operator and monitor boots simultaneously leading to possible overpressure of downstream (>10% MOP). Code non-compliance, reporting to TSSA is required
637	Hagar Groundwater Contamination	Wes Armstrong	Groundwater contamination is present at the Hagar facility, and there is evidence that it has migrated off-site. Despite the presence of offsite groundwater treatment units the contamination has possibility to migrate further.	Contaminated Soil and Water	Hagar LNG has soil and groundwater contamination underlying the property due to historical operations.	The groundwater at and in the vicinity of the site is contaminated with volatile organic compounds (VOCs) within the fractured gneiss bedrock at level above applicable Ministry of the Environment, Conservation and Parks (MECP) Ontario Regulation 153/04 (O.Reg. 153/04) Table 6 Standards for shallow soils in a potable groundwater condition. VOCs of concern may include: vinyl chloride (VC); 1,1-dichloroethylene (DCE); 1,1-dichloroethane (DCA); and 1,1,1-trichloroethane (TCA).
638	Hagar LNG Facility- Rare worker safety event due to loss of containment	Wes Armstrong	Rare worker safety event due to loss of containment at Hagar LNG facility	Accidental release/LOC flammable gas	Leaks from site equipment/ piping/ pipeline/ storage tank	release of LNG and potential for fire / explosion leading to injury and fatality
639	Hagar Plant Reliability and ability to supply Sudbury network	Wes Armstrong	Risk of Hagar LNG Facility not being able to supply vaporized LNG when called to do so to supply Sudbury Market. (TC Energy Canadian Mainline at Marten River contractual pressure of 580psig)	Equipment malfunction	Failure of vaporizer system Failure of transmission compression	Inability to supply Sudbury market. Under Design Day (53.6 HDD) conditions, the Sudbury West area would require potential load shed (15,700 regular rate customers (residential and commercial), 3 contract customers across 23 sites)
645	Parkway East Compressor Station and Gate Stations - rare worker safety event due to loss of containment	Wes Armstrong	Parkway East Compressor Station and Gate Stations – rare worker safety event due to loss of containment	Accidental release/LOC flammable gas	Leaks from site equipment	Release of flammable gas and potential for fire / explosion
646	Lisgar Gate Stations - rare worker safety event due to loss of containment	Neil MacNeil	Lisgar Gate Stations – rare worker safety event due to loss of containment	Accidental release/LOC flammable gas	Leaks from site equipment	Release of flammable gas and potential for fire / explosion
648	Improper Use of Pesticides	Jennifer Burnham	Improper use of pesticides causing regulatory fines/orders or environmental harm through bioaccumulation. Pesticides are a regulated compound (Pesticides Act, R.S.O. 1990, c. P.11) and can only be applied under specific circumstances and only specific classes of pesticides are permitted.	Pesticides	1. Application, handling or working with Non-approved Pesticides. 2. Application, handling or working with Non-approved pesticides around non-approved stations. 3. Improper records from the contractors that are required. 4. Use of unlicensed contractors for the usage of pesticides.	Improper use of pesticides can cause environmental harm due to bioaccumulation impacting uplands and confined wetland.
649	Land Alteration Impacts to land or wildlife habitat, including Species at Risk (SAR)	Jennifer Burnham	Land Alteration Impacts to land or wildlife habitat, including Species at Risk (SAR) due to improper environmental permitting.	Land Alteration	1. Not reviewing environmental permits daily prior to work 2. Not identifying environmental permits prior to work (through the planning process)	Land alteration can lead to negative impacts on land, water, air or sensitive environmental receptors (animal or plant species)
650	Sarnia South pipeline – Jane Rd Aerial Crossing Potential A Leak	Angela Scott	An A-leak on the NPS 8 aerial crossing leading to line having to be isolated for couple of weeks.	Corrosion external	The crossing was wrapped in a plastic wrap which has effectively pooled water up against the pipe and accelerated the corrosion.	A-leak requiring emergency line replacement resulting in customer loss (1000+ customers on 10HDD, 1500+ customers on a design day). No ignition.
653	Exposure to Hexavalent Chromium	Holly Adams	Exposure to Hexavalent Chromium, a hazardous material associated with the industrial process when a calcium based anti-seize lubricant reacts to high temperatures and friction from the stainless steel blades in the gas turbine engines (Solar, Rolls Royce and GE, Siemens). Overexposure through inhalation can cause occupational illness (acute and chronic) while working in or around the affected engines in specified GDS facilities. The hazardous material is a sensitizer. Repeated skin exposure to the residue can cause an allergic reaction or skin irritation causing acute and/or chronic illness.	Exposure to toxic, explosive or oxygen deficient atmosphere	Contact with the residue created during the industrial process when a calcium based anti-seize lubricant reacts to high temperatures and friction from the stainless steel blades in the gas turbine engines (Solar, Rolls Royce and GE, Siemens).	**H&S:** Potential for cancer due to overexposure through inhalation or skin contact. **Justification:** > C5 because there is a potential for cancer > L1 because air monitoring shows it is well below exposure limits and the residue tends to be baked on
654	Wells without Intermediate Casing	Steve Pardy	8 wells in the Kimball-Collinville field have been identified that do not contain an intermediate casing. The intermediate casing is generally installed during drilling to provide protection while drilling into gas pressure in the reef. In addition, the intermediate provides a second string of casing above the F Shale formation to protect the casing from the potentially corrosive fluids contained in the Detroit River formation. The intermediate casing is required to meet the current provincial standards and CSA Z341. If the production casing fails this could result in accidental release of flammable gas.	Accidental release/LOC flammable gas	1. Wells were drilled prior to CSA Z341 and are grandfathered and therefore the intermediate casing was not required. 2. Loss of containment due to various causes	If the casing failed and the rock formation was exposed to full reef pressure there is potential that gas could escape outside the reef and inability to identify the source of the leak. Worst case scenario there is a potential for well blowout.
655	Fisher 627 Regulator Bolts Fracture due to Manufacturing Defects	Monica Lavers	Fractured bolts in 627 Regulators with ductile iron or steel bodies (HP and XHP distribution network)	Manufacturing defects	Hydrogen embrittlement during the manufacturing process	Gas escape typically at set point of regulator leading to potential evacuation, fire and explosion. Potential for customer supply loss (system stations)
656	NPS 6 Kingston Lateral - Collins Creek Exposure	Steven Rogers	The NPS 6 Kingston Lateral was built in 1966 and has a 12m exposed section of the NPS 6 Kingston Lateral in the Collins Creek watershed between Princess St and Woodbine Rd, west of the city of Kingston. The exposed section of the pipeline in Collins Creek was discovered during the 2021 Depth of Cover Survey by Dillon Consulting on behalf of Enbridge Gas Inc.	Accidental release/LOC flammable gas	Vintage construction practices, poor/non-existent buoyancy control design	**Operational** - It is the main feed for all of our Kingston network, and as such could result in loss of the majority (or all) of the downstream system, potentially impacting greater than 21,000 customers.
657	Storm/Sump Pump Lateral Crossbore Risk	Tara Kuuskman	Potential cross bore to storm/sump pump laterals and a lateral mechanical augured inside a home creating a potential for gas migration into the home.	3rd party damage	Incomplete Records Incorrect utility identification	Gas line can become compromised if storm/sump line gets cleaned with cutting tool or high pressure water jet potentially leading to a sudden release of natural gas and potential migration to building(s) by direct path through storm sewer. Potentially resulting in building explosion, if LEL is reached and an ignition source is present, with potential for multiple fatalities (Public H&S impact and service disruptions).
662	Mattawa Bridge Crossing Corrosion Risk	Johanna Sanchez Gomez	Severe external corrosion (wall loss >20%, max 57%) due to lack of coating or other corrosion protection on 9 locations on the bridge crossing (120m)	Corrosion External	External corrosion due to lack of coating or other corrosion protection	Multiple B leaks (1 active B leak) requiring planned repair or replacement
663	Encroachment activities causing noise offsite impacting public	Jennifer Burnham	Encroachment activities causing noise offsite impacting public with reduced separation distances between residential areas and GDS facilities.	Elevated noise from operating GDS Assets	Increase in encroachment to GDS-owned facilities (Distribution Operations Stations, STO stations and facilities	Causing media and regulatory impacts and residential complaints NOTE: Evaluated based on media coverage and regulatory impact, both are grouped into reputational per current matrix. Env: No impacts to the Environment as per the current 7X7 matrix.
664	Liquid Contaminants and Petroleum Hydrocarbons in Stations	Darryl Arnold	Liquid Contaminants and Petroleum Hydrocarbons in Gate, Distribution, Customer Stations from unknown sources	Off spec gas	Liquid Contaminants and Petroleum Hydrocarbons from unknown sources	Excessive liquid in gas resulting in damages in costumer HVAC equipment and financial impact. Liquid causing equipment damage at station resulting in atmospheric venting through station relief valve. This issue creates health and environmental impact and potential contract customer losses
665	Hagar KVG Engine Impacts to LNG	Nicole Lehto	Condition issues have been identified on Hagar's KVG engine. An unplanned outage due to a crankshaft failure would eliminate our ability to liquify for a minimum of two operating seasons. The risk of vapourized LNG not being supplied when required this heating season and next was evaluated with the assumption that the KVG Engine cannot be run until mitigation has been implemented.	Operate beyond allowable limits	Inability to liquify due to condition issues, leading to inadequate LNG supply	Inability to meet design day gas requirements leading to customer loss in Sudbury (~15,000 customers)
666	St Laurent Pipeline - Corrosion and Third-Party Damage	Jean-Benoit Trahan	The St. Laurent North Pipeline system is comprised of 10.7 km of NPS 12 pipe and 0.4 km of NPS 16 pipe. The pipeline was originally constructed in 1958 - 1959 with coated steel pipe. A Quantitative reliability assessment determined the overall risk of a failure on the pipeline using historical information, best practice reliability models and compared to industry benchmarks.	3rd party damage	3rd party damage, SSWC, manufacturing, delayed failure of mechanic damage, fabrication and integration of threats leading to pipeline rupture and large leak	Operational: The St. Laurent Pipeline is a critical pipeline that directly or indirectly serves natural gas to approximately 165,000 customers in the City of Ottawa and Gatineau, Quebec. In the event emergency repair activities force an unplanned outage, projected customer losses for a 1 Degree Day (17C) and 47 Degree Day (-29C) range between 16,000 to 62,000 customers, respectively

Current ID	Controls	Control Category	Risk Category	Impact Category	Likelihood	Consequence	Risk Rank	Risk Region
632	1) Keep Stage 156 high in pressure.	Prevent	Operational reliability	Operational	2	7		
633	Animal Attack Prevention Training** Site Assessment ** Situational Awareness ** Work order communication Program (Maximo)	Prevent Detect Prevent Prevent	Workforce safety	Health & Safety	6	3		
634	Site Assessment ** Situational Awareness/Communication ** Personal Protective Equipment Insect & Tick repellant Tick removal kits including testing Pest Training*	Detect Prevent Mitigate Mitigate Mitigate Prevent	Workforce safety	Health & Safety	4	3		
635	1. Locate delivery processes and procedures 2. Public awareness activities 3. Contractor management activities 4. Industry association participation	Prevent Prevent Prevent Prevent	Operational reliability	Reputational	4	3		
636	Operator response to a gas control alarm or ERX alarm (at some stations), token relief and emergency call, or detected in a maintenance cycle - Monitor regulator - Routine scheduled maintenance - emergency response procedures	Detect Detect Detect Mitigate	Operational regulation	Reputational	7	2		
637	**Groundwater Treatment Units**: There are 5 groundwater treatment units in place: 1 on Site for Enbridge operations, and 4 off Site for use on residential neighbouring properties. **Groundwater Monitoring:** 1. EGI monitors groundwater conditions on an annual basis. 2. On-Site groundwater treatment unit monitored on a monthly basis. 3. Off-Site water treatment units monitored on a quarterly basis. **Signage**: Onsite drinking water is separate and tap are clearly signed to avoid accidental ingestion of contaminated groundwater.	Mitigate Detect Prevent	Environmental	Environmental	3	6		
638	Primary Containment/Berm Fire and Gas Detectors and Alarms Inspection and maintenance (ECS Manual - Storage and Transmission Operations (STO) Emergency Response Plan (ERP)	Prevent Detect Prevent Mitigate	Workforce safety	Health & Safety				Conditionally Tolerable Region
639	Redundancy in Transmission Compressor (2 X 100%) and Vapourizers (3 X 50%) Telemetry Inspection and maintenance, Operations (ECS Manual - Storage and Transmission Operations (STO)) Sudbury Load Shed Plan	Prevent Detect Prevent Mitigate	Operational reliability	Operational	1	7		
645	Fire and Gas detection. Integrity Management Plan. Emergency response procedure/plan.	Detect Prevent Mitigate	Workforce safety	Health & Safety	N/A	N/A	N/A	Conditionally Tolerable Region
646	Fire and Gas detection. Integrity Management Plan. Emergency response procedure/plan.	Detect Prevent Mitigate	Workforce safety	Health & Safety	N/A	N/A	N/A	Conditionally Tolerable
648	> Legacy EGD - E-PRO-113: Vegetation, Soil and Restoration Management. > Contractor Management Program - Pesticides Applicator License > C&M Manual - Vegetation Management - Section 37 (LEG) > Personal Protective Equipment > Site Assessment > Situational Awareness > Environmental Obligations tracker and procedure	Mitigate Prevent Prevent/Detect Prevent Prevent Prevent/Detect Prevent	Environmental	Environmental	2	4		
649	LEGD: E-PRO 106 - Heritage Resource Management E-PRO-102 - Environmental Site Assessment and Screening E-PRO-112 - Environmental Compliance Approvals C&M Manual Section 7.5 - Water and Environmental Permits C&M Manual Section 15.2 - River and Creek Crossings - Permits PDR Manual Section 2.12 - Pipeline Route Selection Procedure PDR Manual Section 4.3.2 - River and Watercourse Crossings PDR Manual Section 6.1.1 Activities Related to Planning and Design Approvals and Responsibilities LUG: - Lands, Permitting and Environment Manual - Environmental Procedures for archaeology, environmental Assessments, Environmental Permitting, etc. - EHS Manual Section 20 - Environmental Compliance Approval	Prevent/Detect Prevent/Detect Prevent Prevent Detect Detect Prevent/Detect Prevent Prevent/Detect	Environmental	Environmental	3	6		
650	1. Leak Survey - Crossing Inspections as part of Leak Survey SOP (Repair and replacement work identified as part of surveys) 2. Corrosion Survey SOP 3. Emergency response procedures	Detect Detect Mitigate	Operational reliability	Operational	3	5		
653	Substitute and remove (in progress) PPE Safe handling procedure (Pipeline Contaminants) - interim Situational Awareness (have communicated the hazard) Housekeeping (remove the exposure; cleaning supplies in progress) Direct reading test sticks/swabs	Prevent, Detect Prevent Mitigate Prevent Mitigate Detect	Workforce safety	Health & Safety	1	5		
654	- Inspection : Visual Inspection - Physically attend each wellsite and check for leaks, corrosion; Check corrosion inhibitor level - Quarterly - Casing Inspection Logs: Physical Inspection of Casing 5YR Frequency - Storage downhole integrity management program -Cement at the surface (Verification plan in process) - Emergency Processes in various manuals - C&M, EH&S, and ERP (Emergency Response Plan) - Operating standards for underground storage - Environment incident guide - Existing Pressure test results of the wells (Production casing and well head) - Integrity Plan for individual wells.	Prevent Prevent Prevent/Detect Prevent Mitigate Prevent/Detect Prevent Detect Prevent/Detect	Public safety	Health & Safety	2	6		
655	1. Low gas pressure alarms at system stations level 2. Multiple runs or bypass available at system stations 3. Provision to shutdown main via valves or remote squeeze 4. Odor Call 5. Investigation and communication (memo and safety alert)	Detect Prevent Mitigate Detect Mitigate	Public safety	Health & Safety	1	6		
656	- Depth of Cover program. - Condition Monitoring program (ECDA). - Leak Survey. - Gas is odourised. - Isolation Valves on the line. - Pressure alarms on SCADA. - Load Shed plan. - GDS Spill Response Procedure - GDS Spill Response Process	Detect Detect Detect Detect Prevent/Detect Detect Mitigate Mitigate Mitigate	Operational reliability	Operational	2	7		
657	- PICS (Pullback Inspection Camera System) - Storm/sump lines are not typically accessible for cleaning tools - Sewer Safety Program (includes storm/sump lines) - Call before you clear/proactive investigation projects and locate process - Emergency processes in various manuals - C&M, Sewer Safety, EPM (Emergency Procedures Manual) - Communication with plumbing companies - Cross bore tool - probability tool gone live.	Detect Prevent Prevent Prevent Mitigate Prevent Detect	Public safety	Health & Safety	1	6		
662	-Weekly leak monitoring of the active B leak -Gas is odourised -Isolation valve identified and checked -Temporary bypass is being approved by Engineering -Pipe hangers are being replaced in mid Dec 2022	-Detect -Detect -Mitigate -Mitigate -Mitigate	Operational reliability	Financial	5	4		
663	- Environmental Compliance Approvals (ECA)/Environmental Activity and Sector Registry (EASR) - permit procedure which needs to demonstrate operations meet requirement, if not, it requires controls to be in place. - Engineering design such as physical barriers (e.g., berms, walls) - Noise Modeling exercises - EHS Manual Section 20.1 - Environment Compliance Approval - EPRO 112 - Environment Compliance Approval Management - Environment Compliance Approval Training - Complaints log - Operation/Maintenance Manuals - TSSA, ESA Field Approvals - Land Acquisitions (STO - Existing investments in Copperleaf)	Prevent, Detect, Mitigate Mitigate Prevent, Mitigate Prevent, Mitigate Prevent, Mitigate Prevent, Mitigate Prevent	Environmental	Financial	5	4		
664	- Filter separators at large stations - Filter separators at some customer stations (newly installed) - customer load is reduced - Liquid monitoring (location and temperature) by operator - Liquid draining by operator - PPE	Mitigate	Operational reliability	Operational	5	4		
665	Gas monitoring/SCADA	Detect	Operational reliability	Operational	6	7		
666	-Damage prevention program -Emergency response program	Prevent Mitigate	Operational reliability	Operational	5	6		

Current ID	Treatment Plan Description	Treatment Owner	Proposed Timeline	Comments	Additional Risk Ranking	Associated Management Program	Latest Update made to Register:
632	14.2.1.1.1 Modeling to determine if increase in tariff may need to reviewed if necessary to reduce operating time. 14.2.1.1.2. Evaluate the additional blending at Kirkwall to result in lower number at Parkway (for in franchise transfer)	Jeff Falkiner		NOTE: OPT of 2 impacted as see a decrease seen in useful lifespan due to compressed maintenance schedule, with the maintenance still being done. Likelihood of 7 as it happens every year.	-For the full results, refer to the full report	MP-01: Asset	6/22/2022
633				November 10, 2021 - Changed MP from MP-02 to MP-04		MP-04: Health & Safety	6/13/2022
634						MP-04: Health & Safety	11/10/2021
635	• Coordinating with Ontario One Call on locate intake and management models/ enhancements to support risk remediation • Coordinating with LAC partners on locate delivery models/ enhancements to support risk remediation • Coordinating with Industry partners to study the effects of Bill93.	Michael McGivery	Q1 2023	Treatment plan proposed timeline added as Q1 of 2023	Financial: Likelihood 1, Consequence 3	MP-07: Damage Prevention	10/5/2022
636				Based on the Risk Workshop, recommendation has been identified: Initiate review to evaluate appropriate mitigation measures (temporary and permanent) to reduce the risk of overpressure of downstream (>10% MOP). This review will be led by FIMP on behalf of Stations Engineering. Nonetheless, the accountability still lies with Stations Engineering specifically if modifications/designs are required as part of mitigation. 03/27/2023 AMH - Updated Risk Owner from A. Nossair to R. Sterling	Financial: L2 C5 Public H&S: L7 C1 Worker H&S: L7 C1 Env: L7 C1 Operational: L7 C2	MP-05: Integrity	3/14/2022
637	1) Onsite Supply Well Review 2) Preliminary Environmental (Human Health and Ecological) Risk Assessment 3) Onsite Groundwater Contamination Delineation Program 4) Remedial Options Evaluation *See Decision Record for more details on the above treatment plan options	Erin Nolan	Q4 2023	Q4 2022 Update COMPLETED -Onsite Supply Well Review -Annual groundwater monitoring -Onsite Groundwater Contamination Delineation Program (Drilling\sampling) -Preliminary Environmental (Human Health and Ecological) Risk Assessment (Memo) IN PROGRESS -Remedial Options Evaluation (postponed) Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023 Timeline changed from 2022 to Q4 2023. Remedial options are being updated - 5/2/2023	Health and Safety: Likelihood 3, Consequence 4 Financial: Likelihood 4, Consequence 3 Reputational: Likelihood 4, Consequence 4	MP-03: Environmental	5/2/2023
638				Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023		MP-01: Asset	2023-02-28
639				Delivery pressure at Marten River is historically @ 800psig (Contract pressure is 580psig) in which case only 3 10^3m^3/hr of LNG required on Design Day (53.6 HDD) with interruptibles OFF Develop plan for better understanding asset condition. Ensure Jenmar recommendations are addressed, and important performance measures are diligently tracked to reveal performance degradation Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023		MP-01: Asset	2023-02-28
645				Risk Results based on individual risk criteria. Further risk reduction measures to be identified as risk is in Region 2 (conditionally tolerable) to reduce the risk to As Low as Reasonably Practicable (ALARP) Risk Owner changed from Peter Jurgeneit to Wes Armstrong 2/28/2023		MP-01: Asset	2023-02-28
646				Risk Results based on individual risk criteria. Relocating equipment to another location may increase the risk at the proposed location of Parkway East. The risk of relocation has not yet been considered in a risk assessment		MP-01: Asset	2022-07-12
648				Financial: Regulatory Fines as per Pesticides Act, R.S.O. 1990, c. P.11 can be up to a maximum of 250K for continuous non-compliance. Reputation: Improper use of Pesticides would lead to Non compliance with Pesticides Act, R.S.O. 1990, c. P.11 that may result in monetary penalty; may require corrective actions.	Financial: L1 C3 Reputational: L2 C4	MP-03: Environmental	2022-07-12
649	1. Ongoing Integration of Environmental Processes and Procedures with awareness in Environmental Permitting. 2. Awareness of integrated Worksite Hazard Checklists and Job Planning Checklists.	Erin Nolan	1. Q4 2023 (Integration) 2. Q4 2022	Financial: Financial impacts might be as result of remediation activities that needs to be done after Land Alteration Reputation: Regulatory enforcement (fines/orders) Operational: Moderation diversion of Enbridge resources as a result of remediation activities. Treatment number 2 is complete. - 5/2/2023	Financial: L2 C4 Reputational: L2 C4 Operational: L2 C3	MP-03: Environmental	2023-05-02
650	Short Term: Monthly leak survey of the crossing Long Term: Replacement of the crossing with below grade pipe. Abandoning aerial crossing. Treatment to be part of the plan for Sarnia South line. Copperleaf investment #740747	Patrick Finniss Mike Cincurak	12/31/2024	Due to location an A-leak is less likely. No source of ignition and no residents in the immediate area. 1000-1500 customers loss depending on the time of the year. 1000-1500 customers losing heat will likely expand beyond local area in terms of media attention due to recent gas explosion in the area. Not completed yet due to budget being deferred. Timeline set to TBD for now. - 5/2/2023 Copperleaf investment number added to long term treatment plan. Proposed timeline updated from 2022 to the end of 2024. - 5/11/2023	Reputational: L3C4 (M) Financial: L3C3 (L) Health & Safety: L3C1 (L) Environmental: L3C1 (L)	MP-01: Asset	5/11/2023
653	1) Air Monitoring (Bright B, Parkway C) 2) Safe Handling Procedure to capture all controls (swab, laundry, handling, disposal, signage/notification) 3) Training (WHMIS Field)	Jae Cho	1) Q4 2022 2) Q4 2022 3) Q4 2023	**Likely Case Scenario Ranking: H&S L3 C3** **H&S:** Occupational illness due to overexposure through inhalation or skin contact causing pulmonary and skin sensitization **Justification:** C3 because there is the potential it will just create a sensitization reaction that could result in modified work restrictions or medical aid. Could select C4 for occupational illness, however likelihood does not justify L3 because we have had no history of sensitization at LUG STO		MP-04: Health & Safety	2022-10-13
654	1. Pressure Test of the wells 2. Verification of Cement at Surface 3. Physical Inspection of Casings	Michael Learn	1. Q4 2023 2. Q4 2023 3. Q4 2022	Treatment plan number 3 is complete - 5/2/2023	Environmental: L2 C3 Low Financial: L2 C5 Medium Reputational: L2 C5 Medium Operational: L2 C4 Low	MP-05: Integrity	5/2/2023
655	Implementation of Corrective Action Plan (replacement plan, procedure(s), timing-logistics) in all regions by Q1 2023.	Kirby Skinn-Jones	Q1 2023	- Likelihood of 1 is selected since this event started to happen in 2022 and no prior incident was known. - Financial risk is only based on replacement associated cost for the overall program. - The replacement focuses on regulators manufactured between Nov 1, 2019 through Jan 21, 2022 as identified by Emerson. Treatment Owner changed to Kirby Skinn-Jones 2/8/2023	Operational: L1 C5 Low Financial: L1 C3 Low Environmental: L1 C2 Low Reputational: L1 C3 Low	MP-01: Asset	2023-02-08
656	**Short Term:** 1. ECDA Monitoring of the section of interest between Princess St. and Woodbine Rd. 2. Field Level Re-Assessment of the pipeline exposure - Q4 2023 3. Annual Review of the Water Survey of Canada (WSC) Hydrometric Station Information (Station ID 02HM005) for annual flood data and potential scour. **Long Term:** 1. NPS 6 Pipeline Replacement Copperleaf Investment: 100703	**Short Term:** 1. Pat Gribbon 2,3: Nick Molnar **Long Term:** 1. Andrea Berkuta	**Short Term:** 1. Q4 2023 2. Q4 2023 3. Q4 2023 **Long Term:** 1. Q4 2027	**Additional Consequences:** **Environmental** - Pipeline failure in a sensitive wetland with possible species at risk, in close proximity with possible species at risk and habitat, including Blanding's Turtle. **Financial** - In the event of a failure, repair and damage costs, Re-light of customers, potential costs associated with environmental permitting, construction, access, et **Reputational** - Disruption or inconvenience affecting 21,000 Customers (DOE Estimate) **Health and safety** - Due to the location of the pipeline and its proximity from any public places there is no impact for Public and Employee health and safety. However, In an event of a failure there is a potential for elevated stress levels for the employees who are addressing the failure.	Environmental: L2 C6 Medium Financial: L2 C4 Low Reputational: L2 C5 Medium Health and Safety: L2C2 Low	MP-05: Integrity	2023-01-18
657	Recommended treatment plan → (aligns with Risk ID 269: Sewer Crossbore Program) • Execute Sewer Lateral Cross Bore Program • Complete the annual proactive inspections plan • Evaluate acoustic inspection technology for identifying legacy cross bores	Wendy McDowell	Ongoing	Likelihood of cleaning a storm/sump line is lower than a sewer line since it only carries water. Lower likelihood of damage from cleaning. Storm/sump lines are harder to locate compared to sewer lines. This is house specific depending on the time of installation. Cost of a house replacement/repair >$1M Q1, 2022 Treatment Summary Execute Sewer Lateral Cross Bore Program Complete the annual proactive inspections plan Evaluate acoustic inspection technology for identifying legacy cross bores Q1, 2022 Status update -2022 proactive inspections issued to Damage Prevention for execution -Setting up agreement with acoustic inspection vendor -Probability model for cross bore to be updated later this year Risk Owner updated from A.S on August 1, 2023	Financial L1C4, Operational L1C2, Reputational L1C4	MP-05: Integrity	2023-08-01
662	Short Term: Survey the full crossing after hangers replacement (Complete December 2022) Long Term: Pipe replacement at the earliest opportunity (2024)	Shane Korbely	2024		Scenario 1: Financial L7C1 Health & Safety L7C1 Environmental L7C1 Operational L7C1 Reputational L7C2 Scenario 2: Financial L5C4 (Lead Risk Entry) Health & Safety L5C1 Environmental L5C1 Operational L5C3 Reputational L5C3	MP-05: Integrity	3/17/2023
663				The scope of this risk does not cover the overall encroachment consequences but only the noise concerns related to it. A further assessment is recommended for overall encroachment risk		MP-03: Environmental	4/21/2023
664	Investigate establishing mitigation measures/ action plans after obtaining samples from upstream 16" and 20" pipeline and Ojibwe and comparing them against Southwest region liquid	Sean Sutton			Worker Health and Safety: L4 C3 Medium Environmental: L4 C3 Medium Financial: L4 C3 Medium Reputational: L4 C2 Low	MP-05: Integrity	4/27/2023
665	Treatment includes a complete compressor foundation block replacement (~$4M) and an Engine/Compressor Overhaul (~$2M). The long-term solution must begin execution in 2023 to support the 2024 liquefaction campaign (by April of 2024). The proposed scope of work includes: 1. Remove compressor from the foundation block 2. Initiate overhaul, identify complete overhaul scope and order any long lead items. (Target to complete overhaul work in 2023) 3. Initiate compressor foundation block replacement as soon as possible (~6 months required for this work) 4. Return overhauled compressor to new foundation block (Spring 2024) 5. Begin 2024 liquefaction campaign (Spring 2024)	Jeff Falkiner	2024			MP-05: Integrity	6/13/2023
666	Short Term: Enhanced 3rd party damage prevention measures including daily ROW patrols, on-site supervision, enhanced public awareness campaign and increase pipeline markers Long Term: Pipeline replacement (pending OEB approval)	Michael McGivery (Short Term) Long-term (TBD)	2025	*Risk Ranked using new Enbridge Risk Matrix	L7C3 Financial L3C5 H&S	MP-05: Integrity	6/30/2023

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 167

To provide a corrected version of the spreadsheet at page 42 of the SEC compendium, Exhibit K14.3.

Response:

Please see Attachment 1.

SEC Filed Enbridge Gas Distribution - Earnings & Return Above OEB Approved ROE

	A	B	C	D	E
	ROE above OEB Approved (3)	**Gross Earnings Above OEB Approved ROE ($M) (4)**	**ROE with Deadband Above OEB approved ROE (1)**	**ROE Deadband**	**Common Equity ($M) (2)**
2019	1.49%	95.9	-0.01%	1.50%	4,730.0
2020	0.20%	13.3	-1.30%	1.50%	4,882.3
2021	0.83%	46.5	-0.67%	1.50%	4,119.8
2022	0.70%	52.7	-0.80%	1.50%	5,537.3
2023	TBD	TBD	TBD	TBD	TBD
Total		***208.4***			

(1) 1.8-SEC-85, Attachment 1, p.13-16, Ln 22

(2) 1.8-SEC-85, Attachment 1, p.13-16, Ln 19

(3) C + D

(4) (A x E)/73.5%

Corrected Enbridge Gas Inc - Earnings & Return Above OEB Approved ROE

	A	B	C	D	E
	ROE above OEB Approved (3)	**Gross Earnings Above OEB Approved ROE ($M) (4)**	**ROE with Deadband Above OEB approved ROE (1)**	**ROE Deadband**	**Common Equity ($M) (2)**
2019	1.50%	96.2	-0.01%	1.50%	4,730.0
2020	0.20%	13.1	-1.30%	1.50%	4,882.3
2021	0.83%	57.7	-0.67%	1.50%	5,119.8
2022	0.86%	64.4	-0.64%	1.50%	5,537.3
2023	TBD	TBD	TBD	TBD	TBD
Total		***231.4***			

(1) 1.8-SEC-85, Attachment 1, p.13-16, Ln 22 for 2019-2021. EB-2023-0092 Exhibit B, Tab 1, Schedule 1 Ln 24 for 2022

(2) 1.8-SEC-85, Attachment 1, p.13-16, Ln 19 for 2021. EB-2023-0092 Exhibit B, Tab 1, Schedule 1 Ln 21 for 2022

(3) C + D

(4) (A x E)/73.5%.

The amounts in column B differ for years 2019 and 2020 due to the values being rounded in column C in SEC's calculation. The 2021 amount differs due to an incorrect common equity amount used in SEC's calculation. The 2022 amount differs as a result of SEC's calulation being based on preliminary 2022 Utility results, whereas the corrected numbers are based on final 2022 utility results, filed in the EB-2023-0092 ESM and Deferral Account Dispostion application.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 172

To provide for each year a net income impact of the integration capital projects.

Response:

Please see Attachment 1 for the net income impact each year from integration capital projects. Enbridge Gas has considered the O&M synergies and costs, in addition to the capital costs, in order to account for the full economics of the integration projects, which would have consisted of both O&M and capital components.

As demonstrated in Attachment 1, the synergies generated during the rebasing term were just enough to cover the integration costs recognized during the same period. At rebasing in 2024, Enbridge Gas is passing on $86 million in annual synergy savings to ratepayers and is seeking recovery of $119 million of undepreciated integration capital which helped generate those savings. These synergies should continue to fund the depreciation of this capital investment and this would have been the case had a longer deferred rebasing term been approved.

	2019	2020	2021	2022	2023	Total
Synergies [1]	32	52	71	86	86	328
Integration costs -O&M [2]	(52)	(124)	(50)	(35)	(20)	(280)
Tax Variance Deferral Account [3]	-	(4)	(10)	7	0	(7)
Operating Cost Net of Synergies	**(19)**	**(75)**	**11**	**57**	**67**	**41**
Depreciation[4]	(0)	(8)	(14)	(23)	(25)	-(70)
Earnings before interest and taxes	**(20)**	**(83)**	**(3)**	**35**	**42**	**(29)**
Interest Expense[5]	(0)	(1)	(2)	(3)	(3)	-(8)
Earnings before taxes	**(20)**	**(84)**	**(4)**	**32**	**39**	**-(37)**
Taxes	10.2	24.7	17.3	(4.6)	(6.7)	-41
Net income	**(10)**	**(59)**	**13**	**27**	**33**	**4**

Notes:
1.Exhibit 1, Tab 9, Schedule 1, page 5
2.Exhibit 1,Tab 9, Schedule 1, page 17
3. Entries to recognize the accelerated versus regular CCA revenue requirement impact, related to integration capital additions, in the Tax Variance Deferral Account.
4. Exhibit 1, Tab 9, Schedule 1, Attachment 1 , Page 4, updated July 6, 2023
5. Ratebase*64%*Debt Rates

	2019(1)	2020(2)	2021(3)	2022(4)	2023(5)
Assumptions					
Long Term Debt	60.90%	63.18%	59.81%	58.84%	61.56%
Short term Debt	3.10%	0.82%	4.19%	5.16%	2.44%
Equity	36.00%	36.00%	36.00%	36.00%	36.00%
Cost of Capital					
Long term Debt	4.45%	4.38%	4.37%	4.25%	4.18%
Short Term Debt	2.04%	0.94%	0.31%	2.31%	3.00%
Equity	8.98%	8.52%	8.34%	8.66%	8.66%

1.Exhibit 6, Tab 1, Schedule 2, Attachment 4, page 2
2.Exhibit 6, Tab 1, Schedule 2, Attachment 4, page 6
3.Exhibit 6, Tab 1, Schedule 2, Attachment 4, page 11
4. EB-2023-0092, Exhibit B, Tab 1, Schedule 5, page 1
5.Exhibit 6, Tab 1, Schedule 2, Attachment 4, page 19

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ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 177

To confirm in writing whether the $24.5 million moved into the real estate and workplace services line is being sought for inclusion in opening rate base in 2024.

Response:

The $24.5 million that was moved from Integration Capital to the Real Estate and Workplace Services line will not be included in opening rate base for 2024. This will reduce the forecast 2024 revenue requirement by $1.6 million.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 183

To provide a list of projects, the year they're being undertaken, and the cost for all projects that similarly are expenditures required to integrate Enbridge Gas distribution under common systems processes and facilities.

Response:

Enbridge Gas defined integration costs as one-time incremental costs required to deliver value for an opportunity or set of opportunities related to utility integration. Integration costs included items such as labour, consulting, and capital expenditures during the MAADs deferred rebasing term. Given the shortened 5-year deferred rebasing term, the Company prioritized the initiatives that would deliver the highest sustainable synergies to the Company and to customers. Upon evaluation of the technical landscape with a shortened deferred rebasing term, the Company had to make a decision regarding its approach to amalgamation. That was to either focus on technology integration or not, given that the shortened time frame would mean that the underlying asset enhancements would not have been fully expensed through depreciation at the time of rebasing. Enbridge Gas recognized that the intent of the MAADs framework was to deliver efficiencies, and the Company believed that the regulatory compact would lead to a fair assessment of the costs incurred to amalgamate at rebasing. By integrating technology platforms, Enbridge Gas was able to reduce costs, increase efficiency and as a result, deliver value to customers through the deferred rebasing term and beyond.

During the upcoming IR term, the Company will employ a prudent, normal course of business approach where investments will be assessed for alignment as technologies reach end of life, or no longer meet business or customer needs. Enbridge Gas will continue to undertake investments that address technology obsolescence as necessary. Enbridge Gas has identified Records Management Technology Obsolescence and Contract Market Technology Obsolescence in future plans. Had these projects been undertaken during the deferred rebasing term, they might have been identified as “Integration Capital” as they address applications used by both legacy utilities.

The Company was directed by the OEB in the MAADs Decision to file a proposal in its next rebasing application for the harmonization of rates[1]. This will mean that the Company will require investments to implement the outcomes of the 2024 Rebasing Decision by the OEB. These projects, inclusive of overhead allocations, are listed below:

- Contract Market Harmonization (Rate & Service Harmonization): $19.2 million, 2023-2026
- General Service Rebasing Changes: $17.9 million, 2024-2025

Enbridge Gas is also planning for two facility investments, previously identified as integration as they align operations across the legacy utility boundaries.

- GTA East: $14.7 million, 2026
- GTA West: $43.2 million, 2025-2026

This integration of facilities was determined through a review of real estate locations and buildings used for office and operational needs, including the review of regional operating boundaries. These changes will optimize facility space, and support effective business operations with teams, machinery and materials in consolidated locations for work execution and response for customers.

[1] EB-2017-0306/EB-2017-0307 Decision and Order, p. 43.

ENBRIDGE GAS INC.

Answer to Undertaking from
Energy Probe Research Foundation (EP)

Undertaking

Tr: 16

To file updated response to board Staff-261 in Exhibit 9, Tab 2, Schedule 1, Attachment 1.

Response:

Please see Attachment 1 for an update to the TVDA balances provided at Exhibit 9, Tab 2, Schedule 1, Attachment 1, lines 9 to 13, to incorporate a true-up to the 2021 balance, 2022 actuals and 2023 forecast reflective of the June 16, 2023 Capital Update.

Please see Attachment 2 for an equivalent update to TVDA balances provided at Exhibit I.9.2-STAFF-261 Attachment 1.

Deferral and Variance Accounts
Actual and Forecast Balances Proposed for Disposition

Line No.	Particulars ($ millions)	Account No.	Period	Forecast to December 31, 2023 Principal (a)	Interest (b)	Total (c)	
1	APCDA - Unamortized Pre-17 Pension Actuarial Losses	179-120	2023	155.2	-	155.2	
2	APCDA - Other	179-120	2019	(1.7)	(0.1)	(1.9)	
3	APCDA - Other	179-120	2020	(14.8)	(0.7)	(15.5)	
4	APCDA - Other	179-120	2021	(13.9)	(0.6)	(14.4)	
5	APCDA - Other	179-120	2022	50.8	1.7	52.5	
6	APCDA - Other	179-120	2023	(33.4)	(0.4)	(33.8)	
7	Subtotal			(13.0)	(0.0)	(13.0)	
8	APCDA - Total	179-120	2023	142.2	(0.0)	142.2	
9	TVDA - Integration Capital Additions	179-383	2020	(3.7)	(0.2)	(4.0)	
10	TVDA - Integration Capital Additions	179-383	2021	**(10.2)**	**(0.7)**	**(10.9)**	/u
11	TVDA - Integration Capital Additions	179-383	2022	**6.9**	**0.4**	**7.3**	/u
12	TVDA - Integration Capital Additions	179-383	2023	**0.3**	**0.0**	**0.3**	/u
13	Subtotal			**(6.8)**	**(0.5)**	**(7.3)**	
14	ICMDA - EGD Rate Zone	179-500	2020	(0.3)	(0.0)	(0.3)	
15	ICMDA - EGD Rate Zone	179-500	2021	0.2	0.0	0.2	
16	ICMDA - EGD Rate Zone	179-500	2022	(4.8)	(0.2)	(5.0)	
17	ICMDA - EGD Rate Zone	179-500	2023	6.9	0.1	7.0	
18	Subtotal			2.0	(0.1)	1.9	
19	ICMDA - Union Rate Zones	179-159	2019	(6.9)	(0.4)	(7.3)	
20	ICMDA - Union Rate Zones	179-159	2020	(5.6)	(0.2)	(5.9)	
21	ICMDA - Union Rate Zones	179-159	2021	(14.4)	(0.5)	(14.9)	
22	ICMDA - Union Rate Zones	179-159	2022	(0.7)	(0.0)	(0.8)	
23	ICMDA - Union Rate Zones	179-159	2023	1.2	0.0	1.2	
24	Subtotal			(26.4)	(1.2)	(27.6)	
25	ICMDA - Total	Combined	2023	(24.4)	(1.3)	(25.6)	
26	RNGISVA	179-12	2022	-	-	-	
27	RNGISVA	179-12	2023	-	-	-	
28	Subtotal			-	-	-	
29	COVID-19DA	179-384	2020	1.4	0.1	1.4	
30	COVID-19DA	179-384	2021	0.0	0.0	0.0	
31	Subtotal			1.4	0.1	1.5	
32	TIACDA - Unamortized Balance	179-02	2023	39.9	-	39.9	
33	Transitional Pension Balance		2023	(254.6)	-	(254.6)	
34	Total of Balances Proposed for Clearance			(102.2)	(1.8)	(103.9)	

2020 Actual In-Service Additions

Line No.	Accelerated CCA	CCA Pool Capital Addition	CCA Class / Rate	2020 Accelerated CCA	2020 Ending UCC	2021 Accelerated CCA	2021 Ending UCC	2022 Accelerated CCA	2022 Ending UCC	2023 Accelerated CCA	2023 Ending UCC	2023 Ending Cumulative Impact
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Energy Services - Scada and Gas Control Consolidation	711,933	Class 12 100%	711,933	-	-	-	-	-	-	-	
2	Energy Services - Scada and Gas Control Consolidation	1,114,524	Class 50 55%	919,482	195,042	107,273	87,769	48,273	39,496	21,723	17,773	
3	Customer Care - CIS Integration - HANA	17,020,480	Class 50 55%	14,041,896	2,978,584	1,638,221	1,340,363	737,200	603,163	331,740	271,423	
4	Customer Care - Customer Experience & Connections	44,854	Class 12 100%	44,854	-	-	-	-	-	-	-	
5	Business Development - Bill Print & Presentment	20,361	Class 12 100%	20,361	-	-	-	-	-	-	-	
6		18,912,152		15,738,526	3,173,626	1,745,494	1,428,132	785,472	642,659	353,463	289,197	

	Regular CCA	CCA Pool Capital Addition	CCA Class / Rate	2020 Regular CCA	2020 Ending UCC	2021 Regular CCA	2021 Ending UCC	2022 Regular CCA	2022 Ending UCC	2023 Regular CCA	2023 Ending UCC	
7	Energy Services - Scada and Gas Control Consolidation	711,933	Class 12 100%	355,967	355,967	355,967	-	-	-	-	-	
8	Energy Services - Scada and Gas Control Consolidation	1,114,524	Class 50 55%	306,494	808,030	444,416	363,613	199,987	163,626	89,994	73,632	
9	Customer Care - CIS Integration - HANA	17,020,480	Class 50 55%	4,680,632	12,339,848	6,786,916	5,552,932	3,054,112	2,498,819	1,374,351	1,124,469	
10	Customer Care - Customer Experience & Connections	44,854	Class 12 100%	22,427	22,427	22,427	-	-	-	-	-	
11	Business Development - Bill Print & Presentment	20,361	Class 12 100%	10,180	10,180	10,180	-	-	-	-	-	
12		18,912,152		5,375,700	13,536,452	7,619,907	5,916,545	3,254,100	2,662,445	1,464,345	1,198,100	
13												
14	CCA Variance			10,362,826		(5,874,413)		(2,468,627)		(1,110,882)		908,904
15	Tax Rate			26.5%		26.5%		26.5%		26.5%		26.5%
16	Earnings Impact of Accelerated CCA			2,746,149		(1,556,719)		(654,186)		(294,384)		240,859
17	Earnings Impact Grossed-up for Taxes			3,736,257		(2,117,986)		(890,049)		(400,522)		327,700
18	TVDA Impact			(3,736,257)		2,117,986		890,049		400,522		(327,700)

	2021 Actual In-Service Additions	CCA Pool		2020		2021		2022		2023		2023 Ending	
	Accelerated CCA	Capital Addition	CCA Class / Rate			Accelerated CCA	Ending UCC	Accelerated CCA	Ending UCC	Accelerated CCA	Ending UCC	Ending UCC	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
19	Engineering - Meter Shop Consolidation	1,745,177	Class 1b 6%			157,066	1,588,111	95,287	1,492,824	89,569	1,403,255		/u
20	Engineering - Meter Shop Consolidation	53,975	Class 8 20%			16,192	37,782	7,556	30,226	6,045	24,181		/u
21	Operations- AWS, Customer Care - CIS Integration / Customer Care - IVR Enhancements and Consolidation, My Account Amalgamation, Unionline Rebranding / Business Development - Website Integration	67,370,370	Class 12 100%			67,370,370	-	-	-	-	-		/u
22	Operations - Customer Connections	555,767	Class 50 55%			458,508	97,259	53,493	43,767	24,072	19,695		/u
23		69,725,288				68,002,136	1,723,152	156,336	1,566,817	119,686	1,447,130		/u

	Regular CCA	CCA Pool Capital Addition	CCA Class / Rate	2021 Regular CCA	2021 Ending UCC	2022 Regular CCA	2022 Ending UCC	2023 Regular CCA	2023 Ending UCC		
24	Engineering - Meter Shop Consolidation	1,745,177	Class 1b 6%	52,355	1,692,821	101,569	1,591,252	95,475	1,495,777		/u
25	Engineering - Meter Shop Consolidation	53,975	Class 8 20%	5,397	48,577	9,715	38,862	7,772	31,089		/u
26	Operations- AWS, Customer Care - CIS Integration / Customer Care - IVR Enhancements and Consolidation, My Account Amalgamation, Unionline Rebranding / Business Development - Website Integration	67,370,370	Class 12 100%	33,685,185	33,685,185	33,685,185	-	-	-		/u
27	Operations - Customer Connections	555,767	Class 50 55%	152,836	402,931	221,612	181,319	99,725	81,594		/u
28		69,725,288		33,895,774	35,829,514	34,018,082	1,811,433	202,973	1,608,460		/u
29	CCA Variance			34,106,362		(33,861,746)		(83,287)		161,330	/u
30	Tax Rate			26.5%		26.5%		26.5%		26.5%	
31	Earnings Impact of Accelerated CCA			9,038,186		(8,973,363)		(22,071)		42,752	/u
32	Earnings Impact Grossed-up for Taxes			12,296,852		(12,208,657)		(30,029)		58,166	/u
33	TVDA Impact			(12,296,852)		12,208,657		30,029		(58,166)	/u
34											
35	CCA Variance - Cumulative			28,231,950		(36,330,373)		(1,194,169)		1,070,233	/u
36	Tax Rate			26.5%		26.5%		26.5%		26.5%	
37	Earnings Impact of Accelerated CCA - Cumulative			7,481,467		(9,627,549)		(316,455)		283,612	/u
38	Earnings Impact Grossed-up for Taxes - Cumulative			10,178,866		(13,098,706)		(430,551)		385,866	/u
39	TVDA Impact - Cumulative			(10,178,866)		13,098,706		430,551		(385,866)	/u

	2022 Actual In-Service Additions	CCA Pool		2020		2021		2022		2023		2023 Ending	
	Accelerated CCA	Capital Addition	CCA Class / Rate					Accelerated CCA	Ending UCC	Accelerated CCA	Ending UCC	Ending UCC	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
40	Engineering - Meter Shop Consolidation	(944)	Class 1b 6%					(85)	(859)	(52)	(807)		/u
	Operations - AWS												
	Energy Services - Cost of Gas Replacement												
	Operations - Estimating and Forecasting												
	Energy Services - Weather & Demand Harmonization												
41	Customer Care - Customer Attachments	32,350,842	Class 12 100%					32,350,842	-	-	-		/u
42	Operations - Emergency Solutions Harmonization	1,936,446	Class 50 55%					1,597,568	338,878	186,383	152,495		/u
43		34,286,345						33,948,325	338,019	186,331	151,688		/u

	Regular CCA	CCA Pool Capital Addition	CCA Class / Rate	2022 Regular CCA	2022 Ending UCC	2023 Regular CCA	2023 Ending UCC	Ending UCC	
44	Engineering - Meter Shop Consolidation	(944)	Class 1b 6%	(28)	(915)	(55)	(861)		/u
	Operations - AWS								
	Energy Services - Cost of Gas Replacement								
	Operations - Estimating and Forecasting								
	Energy Services - Weather & Demand Harmonization								
45	Customer Care - Customer Attachments	32,350,842	Class 12 100%	16,175,421	16,175,421	16,175,421	-		/u
46	Operations - Emergency Solutions Harmonization	1,936,446	Class 50 55%	532,523	1,403,924	772,158	631,766		/u
47		34,286,345		16,707,915	17,578,429	16,947,524	630,905		/u
48	CCA Variance			17,240,410		(16,761,193)		479,217	/u
49	Tax Rate			26.5%		26.5%		26.5%	
50	Earnings Impact of Accelerated CCA			4,568,709		(4,441,716)		126,993	/u
51	Earnings Impact Grossed-up for Taxes			6,215,930		(6,043,151)		172,779	/u
52	TVDA Impact			(6,215,930)		6,043,151		(172,779)	/u
53	CCA Variance - Cumulative			(19,089,964)		(17,955,362)		1,549,451	/u
54	Tax Rate			26.5%		26.5%		26.5%	
55	Earnings Impact of Accelerated CCA - Cumulative			(5,058,840)		(4,758,171)		410,604	/u
56	Earnings Impact Grossed-up for Taxes - Cumulative			(6,882,776)		(6,473,702)		558,645	/u
57	TVDA Impact - Cumulative			6,882,776		6,473,702		(558,645)	/u

	2023 Forecast In-Service Additions	CCA Pool		2020		2021		2022		2023		2023 Ending	
	Accelerated CCA	Capital Addition	CCA Class / Rate							Accelerated CCA	Ending UCC	Ending UCC	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Energy Services - PowerSpring LVB Integration												
	Operations - AWS Phase 3												
	RACOG - Cost of Gas Applications												
	Leak & Corrosion Integration												
	Dispatch Scheduling Harmonization												
58	Other	34,288,316	Class 12 100%							34,288,316	0		/u
59	Operations - Harmonized Field User Connectivity	175,990	Class 50 55%							145,192	30,798		/u
60		34,464,306								34,433,508	30,798		/u

	Regular CCA	CCA Pool Capital Addition	CCA Class / Rate	2023 Regular CCA	2023 Ending UCC	
	Energy Services - PowerSpring LVB Integration					
	Operations - AWS Phase 3					
	RACOG - Cost of Gas Applications					
	Leak & Corrosion Integration					
	Dispatch Scheduling Harmonization					
61	Other	34,288,316	Class 12 100%	17,144,158	17,144,158	/u
62	Operations - Harmonized Field User Connectivity	175,990	Class 50 55%	48,397	127,593	/u
63		34,464,306		17,192,555	17,271,751	/u
64	CCA Variance			17,240,953		17,240,953 /u
65	Tax Rate			26.5%		26.5%
66	Earnings Impact of Accelerated CCA			4,568,852		4,568,852 /u
67	Earnings Impact Grossed-up for Taxes			6,216,126		6,216,126 /u
68	TVDA Impact			(6,216,126)		(6,216,126) /u
69	CCA Variance - Cumulative			(714,409)		18,790,403 /u
70	Tax Rate			26.5%		26.5%
71	Earnings Impact of Accelerated CCA - Cumulative			(189,318)		4,979,457 /u
72	Earnings Impact Grossed-up for Taxes - Cumulative			(257,576)		6,774,771 /u
73	TVDA Impact - Cumulative			257,576		(6,774,771) /u
78	Annual Impact		(3,736,257)	(10,178,866)	6,882,776	257,576	/u
79	Cumulative Impact	157,388,090		(13,915,123)	(7,032,347)	(6,774,771)	/u

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 113

To file PWC's audit opinion and memo.

Response:

Please see Attachment 1 for PwC's Independent auditor's report which indicates that Enbridge Gas Inc.'s financial position, results of operations and cash flows as at December 31, 2018, are presented fairly, in all materials respects with U.S. GAAP. The report is also provided at Exhibit I.1.8-STAFF-14, Attachment 1, pages 3 through 6.

Please see Attachment 2 for acknowledgment of PwC's review of the accounting memo to support Enbridge Gas's accounting position for Union's pre-February 2017 unamortized actuarial losses and past service costs balance as presented in the December 31, 2018 combined financial statements. The acknowledgement is also provided at Exhibit JT3.31, Attachment 1, page 14.

Tr Vol 15 113, line 15 notes that PwC "signed off on the memo". Enbridge Gas would like to clarify this statement. PwC was given the opportunity to review and comment on the memo prior to finalization to ensure that they understood Enbridge Gas's proposed treatment in the December 31, 2018 combined financial statements and as such would have no issues in providing an unqualified audit opinion.

Independent auditor's report

To the Shareholders of Enbridge Gas Inc.

Our opinion

In our opinion, the accompanying combined financial statements present fairly, in all material respects, the financial position of Enbridge Gas Inc. (the Company) as at December 31, 2018 and 2017, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America (US GAAP).

What we have audited
The Company's combined financial statements comprise:

- the combined statements of earnings for the years ended December 31, 2018 and 2017;
- the combined statements of comprehensive income for the years ended December 31, 2018 and 2017;
- the combined statements of shareholders' equity for the years ended December 31, 2018 and 2017;
- the combined statements of cash flows for the years ended December 31, 2018 and 2017;
- the combined statements of financial position as at December 31, 2018 and 2017; and
- the notes to the combined financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the combined financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the combined financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

Emphasis of matter - Combined financial statements

We draw attention to the fact that, as described in note 1 to the combined financial statements, the businesses included in the combined financial statements have not operated as a single entity. These combined financial statements are, therefore, not necessarily indicative of results that would have occurred if the businesses had operated as a single business during the years presented or of future results of the combined businesses. Our opinion is not modified in respect of this matter.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the combined financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the combined financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the combined financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the combined financial statements

Management is responsible for the preparation and fair presentation of the combined financial statements in accordance with US GAAP, and for such internal control as management determines is necessary to enable the preparation of combined financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the combined financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the combined financial statements

Our objectives are to obtain reasonable assurance about whether the combined financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these combined financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the combined financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the combined financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the combined financial statements, including the disclosures, and whether the combined financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the combined financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Ontario
February 15, 2019

Appendix A – Stakeholder Listing

Stakeholder	**Review Status**
Chris Tuckwell – Director Accounting Operations (EGD/UGL)	Complete
Tanya Ferguson – Director FP&A	Complete
Ryan Small – Manager Revenue and Regulatory Acct (EGD)	Complete
Evgenia Vangelova – Manager Tax Reporting	Complete
Mark Kitchen – Director Regulatory Affairs (UGL)	Complete
Cassell Kincaid – Director Corporate Accounting	Complete
Monica Woodward – Director Financial Reporting	Complete
Jana Murdock – Director Financial Reporting	Complete
Andrew Alonzo – Manager Enterprise Accounting Research (EI)	Complete
Tammy Gillard – Manager Pension Reporting	Complete
Abbas Lahka – External (EY)	Complete
Phil Hagel / Rebecca Shaw – External Auditors (PwC)	Complete

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 144

To confirm why overhead amounts were not included in the E.B.O. feasibility analysis.

Response:

Enbridge Gas confirms that full capitalized overheads, which are included in the capital budget are not included in E.B.O. 188 feasibility assessments. For feasibility assessments of new connections an estimate of incremental overheads is included pursuant to E.B.O. 188, Appendix B, Section 2.1 b). This section of the E.B.O. 188 Guidelines is set out below:

> For capital costs, the common elements will be as follows:
>
> a) an estimate of all costs directly associated with the attachment of the forecast customer additions, including costs of distribution mains, services, customer stations, distribution stations, land and land rights;
> b) an estimate of incremental overheads applicable to distribution expansion at the portfolio level; and
> c) an estimate of the normalized system reinforcement costs.

Incremental overheads rather than fully allocated overheads are used in the analysis as these costs are directly driven by new customer additions.

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 167

To validate whether or not indirect overheads would typically only apply to the projects in the asset management plan

Response:

Indirect O&M overheads are allocated to all projects included in the Asset Management Plan as well as to all projects classified as Integration capital during the MAADs deferred rebasing term. Indirect O&M overhead allocations are not applicable to projects held outside of the Asset Management Plan. This includes Community Expansion projects and regulated Renewable Natural Gas (RNG) and Compressed Natural Gas (CNG) projects. Community Expansion projects are excluded as these are subject to specific regulatory approvals and a 10-year rate stabilization period prior to the review of capital expenditures. RNG and CNG projects are excluded as they are part of the ancillary business and are subject to fully allocated costing in place of indirect overhead allocations.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 41

To provide the allocation of the pension and OPEB amount to capital and OM&A when the capital allocation is based on the total pension and OPEB amount and not just the current service cost.

Response:

Enbridge Gas considers only current service costs in the determination of overhead capitalization, as this is the only component of the net periodic pension cost that can be capitalized under US GAAP. According to ASC 715-30-35-7A, “the service cost component shall be the only component of net periodic pension cost eligible to be capitalized as part of the cost of inventory or other assets.” Therefore, non-current service costs components (interest cost, expected return on assets, etc.) are excluded from burden rates and capitalization.

Additionally, the majority of pension costs are attributable to retired employees and are not related to the ongoing labour costs of active, or newly hired, employees. For example, new hires for a project have no past pension accruals and therefore no interest cost or return on assets. This further supports using only the current service cost attributable to active employees in the calculation of burden rates and capitalization.

Although the Company does not believe it is appropriate to capitalize the non-current service costs components of pension expense, it has estimated the capitalization based on total pension and OPEB expense (and not just the current service cost) in order to be responsive to the undertaking. Forecasted 2024 Capitalized Pension & Benefits costs would decrease from $65.1 million to $60.6 million if total pension costs for active employees were used in the capital allocation as opposed to just the current service cost.

ENBRIDGE GAS INC.

Answer to Undertaking from
Energy Probe Research Foundation (EP)

Undertaking

Tr: 52

To explain the derivation of the figures in the table referred to from Exhibit K16.1; to clarify whether the indirect overheads line takes into account interest during construction and labour.

Response:

Enbridge Gas interprets the question to be in reference to whether the calculation for indirect overheads takes into account interest during construction and also labour that is burdened with 41.7% in loadings. Note that terms 'burden' and 'loading' can be used interchangeably. Please see Attachment 1 which recreates the cost estimate shown in the Energy Probe compendium[1] based on the Panhandle Regional Expansion as filed in the leave to construct application[2].

Enbridge Gas confirms that the labour expense shown on line 2 of the table is inclusive of burdens in the amount of $182,500. The $68.8 million calculated in Attachment 1 also calculates indirect overhead on that amount. However, this is a presentation error with the leave to construct table in Attachment 1. Indirect overheads are actually allocated to direct capital costs excluding both loadings and interest during construction (IDC). The actual indirect overheads for the project would be $76,103 lower than the $68.8 million presented in Attachment 1 (i.e. there would be no indirect overhead on the $182,500).

[1] Exhibit K15.6, page 4
[2] EB-2022-0157

Panhandle Regional Expansion Project
Project Cost

Line No.	Cost Description ($ millions)	Mainline	NPS 36 Stations	Subtotal	Dawn	Total	
1	Materials	$ 28.3	$ 2.2	$ 30.5	$ 26.4	$ 57.0	
2	Labour	2.7	0.2	2.8	0.9	3.8	
3	External Permitting and Land	17.4	-	17.4	-	17.4	
4	Outside Services	130.8	5.4	136.2	42.0	178.1	
5	Contingency	13.9	0.6	14.5	6.3	20.8	
6	Interest During Construction	6.4	0.3	6.7	5.4	12.1	
7	Total Direct Capital Cost	199.5	8.6	208.1	81.1	289.2	
8	Indirect Overheads	48.0	2.1	50.1	18.7	68.8	
9	Total Project Cost	$ 247.5	$ 10.7	$ 258.2	$ 99.8	$ 358.0	
	Total Direct Capital Cost excluding IDC	193.1	8.3	201.4	75.7	277.1	
	Indirect Overhead Rate	24.8%	24.8%	24.8%	24.8%	24.8%	- weighted average of each year's OH rate
	Total Indirect Overheads	48.0	2.1	50.1	18.8	68.8	

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 63

To identify the comparative impact on ratepayers if no indirect overheads were capitalized versus being capitalized and added to rate base, and the comparative impact on ratepayers under the two scenarios.

Response:

The total revenue requirement impact in 2024 of placing overhead costs of $310 million[1] into O&M rather than capitalizing them, is an increase of approximately $348 million, as detailed in Table 1.the impact of recovering the overhead as a period charge (i.e. in 1 year) versus recovering over an extended period of time through depreciation.

Please note that these revenue requirement impacts do not consider any other corresponding impacts that would occur as a result of removing capital additions, such as changes in term debt issuances/requirements.

Table 1
Summary of Revenue Requirement impact of placing overheads into O&M

($ millions)	2024 Revenue Requirement
Increase(Decrease) in Cost of Capital	(5)
Increase(Decrease) in Operations and Maintenance	310
Increase(Decrease) in Depreciation	(5)
Increase(Decrease) in Tax	47
Net Increase(Decrease) in Revenue Requirement	348

The Company has computed the information above to be responsive to the undertaking. In the Company's opinion, it is not appropriate to allocate costs of activities supporting the capital portfolio to O&M. A reduction in the capital program will not translate to an immediate reduction in costs required to support the overall capital portfolio for Enbridge Gas. The resources are required to manage thousands of concurrent and often multi-year capital projects through the initiation, feasibility, planning, approval, design,

[1] Please note that the estimated impacts in Table 1 reflect the Capital Update and do not incorporate the impacts from the settlement proposal.

permitting, stakeholder and customer engagement, construction, governance, supervision, commissioning, records and close out phases of projects. In addition, they may also support non-capital activities, which is why these resources will still be required. The supporting functions that are included in the capitalized overheads include utility functions such as engineering, operations, environment lands, sales, in addition to central functions such as supply chain management, legal, TIS and finance.

The capital portfolio considers thousands of projects, the reduction in the dollars spent or a nominal reduction in the number of projects performed, would not be expected to reduce the support required in the near term. For reference, the project count in 2022 exceeded 4,000 individual investments and program activities. Additionally, reduction of dollars spent on projects does not necessarily mean a proportional reduction of total number of projects. In many cases, projects would have to be split into phases executed over multiple years with smaller scopes to be completed in each year so the most urgent needs can be addressed as soon as practicable. For example, pipeline replacements may be phased into multiple years with shorter lengths of pipe being replaced in each phase; but each phase will require a similar degree of effort to plan and support. This approach, of course would mean more capital spent to achieve the same scope of work over a longer period; but would ensure the most urgent needs are addressed promptly.

As an example, referenced during the Overhead Capitalization panel, Asset Management (tasked with the optimization of the capital portfolio) would not simply increase or decrease head count of full-time employees in response to the annual fluctuations in the level of invested capital or quantum of projects as the functions would still be required, irrespective of a prospective change in the annual capital program.

As another example, within the supply chain management department, irrespective of the amount of capital or the number of projects, the work required would still be the same. Whether the function is purchasing one million units of a particular part or asset, or purchasing 100,000 units, the steps in the process, specification confirmation, approvals, procurement, and inventory support of that item is the same. Similarly, within finance, the invested amount of capital and the number of projects will not have an impact on the finance activities required such as processing journal entries, budgeting forecast and reporting. The work and effort are still the same.

There is a direct correlation, as expected, between the capital portfolio and direct costs. That is, if a project was eliminated, the directly associated costs, such as materials, direct labour, outside services contracted to construct the project in question, would be eliminated. A material and sustained reduction in the capital program could lead to a step-change in the level of indirect costs required to support the capital program if that reduction was sustained over an extended period.

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 67

To confirm if the IT assets are in EI rate base, as opposed to being contracted for outside of EI.

Response:

EI is a parent company and is not regulated. As such, it does not have a regulated rate base. IT assets that benefit the whole enterprise, including Enbridge Gas, are recorded in EI's (parent company's) books and EI recovers the cost of those assets from its business units and affiliates, including Enbridge Gas. IT assets that exclusively benefit Enbridge Gas are in Enbridge Gas's rate base.

Certain TIS services may be contracted to outside vendors. The cost of these services is charged to EI's business units and affiliates when they benefit the whole enterprise. To the extent a cost is incurred for the benefit of a single business unit or affiliate, it gets charged to that specific entity.

ENBRIDGE GAS INC.

Answer to Undertaking from
Industrial Gas Users Association (IGUA)

Undertaking

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To update the table at Exhibit 4, Tab 5, Schedule 1, Attachment 3, page 23 to show the 2024 current methodology.

Response:

Please see Attachment 1 which provides depreciation rates and provisions for the 2024 Test Year based on the current methodologies in place for the EGD and Union rate zones.

2024 Test Year Depreciation Expense - EGI - Current Rates

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate EGD	Rate UGL	Provision
		(a)	(b)		(c)
	Intangible Plant				
1	Franchises and consents	1.2			0.0
2	Intangible plant - Other	0.5			0.0
3	Total	1.7			0.0
	Local Storage Plant				
4	Structures and improvements	7.3	0.00%	2.85%	0.2
5	Gas holders - storage	7.3	0.00%	2.54%	0.2
6	Gas holders - equipment	23.1	0.00%	3.54%	0.8
7	Total	37.7			1.2
	Underground Storage Plant				
8	Land rights	74.8	1.16%	2.10%	1.2
9	Structures and improvements	111.6	1.84%	2.50%	2.6
10	Wells	152.8	1.52%	2.48%	2.8
11	Wells Equipment	16.4	5.56%	0.00%	0.9
12	Field Lines	394.1	1.49%	2.48%	6.5
13	Compressor equipment	742.5	2.60%	2.68%	19.8
14	Measuring & regulating equipment	211.2	2.99%	3.11%	6.3
15	Total	1,703.5			40.0
	Transmission Plant				
16	Land rights	92.4	0.00%	1.76%	1.2
17	Compressor Structures and improvements	166.5	0.00%	2.03%	3.4
18	Measuring and Regulating Structures and Improvements	11.4	0.00%	2.03%	0.2
19	Equipment	3.3	0.00%	0.00%	0.1
20	Mains	2,976.4	0.00%	1.98%	47.1
21	Compressor equipment	1,039.8	0.00%	3.23%	33.1
22	Measuring & regulating equipment	504.6	0.00%	2.60%	12.7
23	Total	4,794.4			97.8

2024 Test Year Depreciation Expense - EGI (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate (2) EGD	Rate (2) UGL	Provision
		(a)	(b)		(c)
	Distribution Plant				
24	Renewable Natural Gas (3)	31.9	Various		1.0
25	Land rights	68.1	1.18%	1.68%	1.2
26	Structures and improvements - Other	215.1	5.24%	2.32%	10.3
27	Structures and improvements - Stoney Creek	33.9	0.00%	2.32%	*
28	Structures and improvements - Win-Rhodes	26.3	0.00%	2.32%	*
29	Structures and improvements - London Admin	22.5	0.00%	2.32%	*
30	Structures and improvements - Kingston Office	19.0	0.00%	2.32%	*
31	Structures and improvements - Mainway	18.1	0.00%	2.32%	*
32	Services - metallic	680.4	2.27%	3.02%	8.9
33	Services - plastic	5,056.3	2.27%	2.56%	138.7
34	Regulators	530.1	2.27%	5.00%	9.0
35	Mains - Envision	181.3	4.03%	0.00%	7.3
36	Mains - coated and wraped	3,857.4	2.44%	2.93%	117.8
37	Mains - plastic	3,969.7	1.85%	2.35%	80.3
38	Company NGV Compressor Stations	13.3	5.97%	4.00%	0.7
39	Measuring & regulating equipment	1,043.2	2.05%	3.72%	26.1
40	Customer M&R Equipment	169.9	0.00%	2.86%	4.8
41	Meters	1,179.3	9.22%	3.93%	77.1
42	Total	17,115.6			483.2
	General				
43	Investment in leased assets	16.3			0.6
44	Structures and improvements - Other	21.7	2.98%	1.92%	2.5
45	Structures and improvements - VPC	90.9	9.93%	0.00%	9.0
46	Structures and improvements - Thorold	0.0	3.61%	0.00%	0.0
47	Structures and improvements - Markham	37.1	2.18%	0.00%	0.8
48	Structures and improvements - Keil	88.1	0.00%	1.92%	*
49	Structures and improvements - Bloomfield	21.6	0.00%	1.92%	*
50	Office furniture and equipment	42.8	10.74%	6.67%	4.3
51	Transporation equipment	146.1	10.56%	13.27%	16.5
52	Heavy work equipment	52.4	3.58%	6.92%	2.7
53	Tools and other equipment	86.6	4.08%	6.67%	4.4
54	Rental - Refuel Appl	2.5	0.74%	0.00%	0.0
55	Rental - NGV Stations	5.3	8.01%	0.00%	0.8
56	Communications structures and equipment	8.3	9.71%	6.67%	0.6
57	Computer Equipment	26.0	36.63%	25.00%	10.7
58	Computer Equipment - post 2023	10.9	0.00%	0.00%	0.0

2024 Test Year Depreciation Expense - EGI (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate EGD	Rate UGL	Provision
		(a)	(b)		(c)
59	Software Acquired Intangibles	103.2	26.32%	25.00%	24.0
60	Software Acquired Intangibles - post 2023	12.0	0.00%	0.00%	0.0
61	Software Developed Intangibles	32.5	21.24%	0.00%	17.5
62	Software Developed Intangibles - post 2023	13.4	0.00%	0.00%	0.0
63	CIS Acquired Software	120.5	10.00%	10.00%	12.3
64	TIS/IT Software	0.0	0.00%	0.00%	0.0
65	WAMS	85.2	10.00%	0.00%	8.3
66	Total	1,023.5			114.9
67	Plant held for future use	1.7	2.27%	0.00%	0.0
68	Total	24,678.1	2.94%	2.78%	737.1

Notes:
(1) Average of the opening and closing plant balances.
(2) Distribution rates for UGL are blended rates for Southern and Northern operations.
(3) Represents forecasted RNG projects in total using a blended rate of assets.
(*) Included in Structures and Improvements - Other

ENBRIDGE GAS INC.

Answer to Undertaking from
Industrial Gas Users Association (IGUA)

Undertaking

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To provide or explain the underlying calculation of net salvage recovery.

Response:

The following response was provided by Concentric Energy Advisors:

Please see Attachment 1 for the tables summarizing the life and net salvage split which results in an accrual related to net salvage of $325,472. In order to complete these calculations, Concentric was required to theoretically split the booked accumulated depreciation account on the basis of the calculated accumulated depreciation. A net salvage accrual of $5 million was referenced in the Oral Hearing on Day 16. After reviewing the calculations, Concentric now estimates the accrual related to net salvage to be $325,472. The resultant depreciation calculations were completed using the Average Life Group procedure with the WACC rate of 6.03% using the life and retirement dispersion estimates as proposed by Emrydia and Intergroup in this proceeding.

Please see Attachment 2 for tables summarizing the life and net salvage split which results in an accrual related to net salvage of $4,878,947. The resultant depreciation calculations were completed using the Average Life Group procedure with the WACC rate of 6.03% for the purposes of discounting the CDNS calculations. The average service life and traditional net salvage estimates underlying these calculations were as per the recommendations of Concentric following the Capital Update filing[1].

As both Attachment 1 and Attachment 2 indicate, when using the Average Life Group procedure with the WACC rate of 6.03% the booked accumulated depreciation amount is in a significantly over-funded position. As such, the annual accrual amount for many accounts is calculated as a negative accrual. This is not possible within depreciation theory, so Concentric has listed the accrual amount as $0 for any account with a negative accrual related to net salvage. Concentric is not of the view that the

[1] See Exhibit 2, Tab 5, Schedule 4, Attachment 1 for Concentric's recommendations in the Capital Update.

accumulated depreciation account related to net salvage is currently significantly over collected. When the more appropriate Equal Life Group with a discount rate of 3.75% is used, the over accrual is lessened. This allows Enbridge Gas to fund annual retirement activities while continuing to accrue for future cost of removal expenses in order to ensure future ratepayers are not burdened with a disproportionate share of future costs of removal.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021

Related to Total Expense

Account		Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LOCAL STORAGE PLANT											
442.00		STRUCTURES AND IMPROVEMENTS	0	40-S5	0%	6,282,181	2,805,060	3,477,121	104,018	25.1	1.66%
443.01		HOLDER - STORAGE TANK	0	45-R4	0%	5,804,412	4,023,544	1,780,869	51,698	20.5	0.89%
443.02		HOLDER EQUIPMENT	0	55-R4	0%	21,554,522	11,363,396	10,191,126	213,953	39.4	0.99%
TOTAL LOCAL STORAGE PLANT						**33,641,115**	**18,192,000**	**15,449,115**	**369,669**		1.10%
UNDERGROUND STORAGE PLANT											
451.00		LAND RIGHTS INTANGIBLE	0	55-R4	0%	74,762,354	45,841,825	28,920,529	1,070,227	24.9	1.43%
452.00		STRUCTURES AND IMPROVEMENTS	0	45-R2.5	-6%	104,433,820	47,148,032	63,551,818	2,102,535	27.8	2.01%
453.00		WELLS	0	45-R2.5	-16%	143,144,395	50,040,540	116,006,958	3,678,752	31.5	2.57%
454.00		WELL EQUIPMENT	0	40-R2	0%	13,364,517	8,575,936	4,788,581	134,706	26.6	1.01%
455.00		FIELD LINES	0	55-R3	-4%	201,920,080	53,298,115	156,698,768	4,252,095	38.2	2.11%
456.00		COMPRESSOR EQUIPMENT	0	44-R4	-3%	682,328,757	228,311,196	474,487,424	14,468,637	31.2	2.12%
457.00		REGULATING AND MEASURING EQUIPMENT	0	40-R2.5	-8%	77,194,133	51,829,828	31,539,836	1,119,637	22.9	1.45%
TOTAL UNDERGROUND STORAGE PLANT						**1,297,148,055**	**485,045,470**	**875,993,914**	**26,826,589**		2.07%
TRANSMISSION PLANT											
461.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	88,171,402	20,599,533	67,571,869	1,409,557	47.6	1.60%
462.00		COMPRESSOR STRUCTURES AND IMPROVEMENTS	0	50-S4	-2%	163,351,958	40,353,631	126,265,367	3,133,351	39.3	1.92%
463.00		MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	0	55-S4	-4%	11,252,284	7,167,268	4,535,107	139,579	27.8	1.24%
464.00		EQUIPMENT	0	50-S4	-2%	2,920,218	523,642	2,454,980	59,463	41.2	2.04%
465.00		MAINS	0	70-R4	-4%	2,783,251,797	919,330,147	1,975,251,722	33,271,473	55.2	1.20%
466.00		COMPRESSOR EQUIPMENT	0	37-R4	-4%	1,005,060,039	331,530,582	713,731,859	24,090,310	27.8	2.40%
467.00		MEASURING AND REGULATING EQUIPMENT	0	40-R4	-9%	395,646,542	119,798,512	311,456,219	10,286,906	29.6	2.60%
TOTAL TRANSMISSION PLANT						**4,449,654,239**	**1,439,303,314**	**3,201,267,122**	**72,390,639**		1.63%
DISTRIBUTION PLANT											
471.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	63,907,560	12,099,619	51,807,941	1,072,013	48.4	1.68%
472.00	*	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-S0.5	0%	220,832,605	64,014,227	156,818,378	5,155,524	29.4	2.33%
472.31		STRUCTURES AND IMPROVEMENTS - STONEY CREEK	2046	40-S0.5	0%	29,662,115	5,056,171	24,605,944	1,180,276	20.8	3.98%
472.32		STRUCTURES AND IMPROVEMENTS - WIN-RHODES	2046	40-S0.5	0%	23,216,546	5,549,955	17,666,591	885,199	20.0	3.81%
472.33		STRUCTURES AND IMPROVEMENTS - LONDON ADMIN	2026	40-S0.5	0%	19,789,902	9,778,917	10,010,985	2,353,163	4.2	11.89%
472.34		STRUCTURES AND IMPROVEMENTS - KINGSTON OFFICE	2046	40-S0.5	0%	16,737,576	4,069,504	12,668,072	628,711	20.1	3.76%
472.35		STRUCTURES AND IMPROVEMENTS - MAINWAY	0	40-S0.5	0%	15,937,297	3,958,252	11,979,045	414,162	28.9	2.60%
473.01		SERVICES - METAL	0	50-L1	-13%	549,648,294	268,325,815	352,776,758	8,745,501	36.2	1.59%
473.02		SERVICES - PLASTIC	0	60-S3	-10%	4,458,883,265	1,384,833,504	3,519,938,088	79,349,017	44.0	1.78%
474.00		REGULATORS	0	50-L1	0%	488,870,931	59,858,893	429,012,038	10,172,494	42.3	2.08%
475.00		MAINS - ENVISION	0	25-SQ	0%	181,264,676	59,887,548	121,377,128	10,469,399	12.2	5.78%
475.21		MAINS - COATED & WRAPPED	0	70-R3	-12%	3,320,418,328	1,051,359,036	2,667,509,492	46,125,241	54.6	1.39%
475.30		MAINS - PLASTIC	0	70-R2	-9%	3,480,106,028	928,431,883	2,864,883,688	49,543,015	57.0	1.42%
476.00		COMPANY NGV COMPRESSOR STATIONS	0	17-S2.5	0%	9,878,703	5,181,735	4,696,968	325,072	10.9	3.29%
477.00		MEASURING AND REGULATING EQUIPMENT	0	40-R2	-5%	950,956,098	367,887,432	630,616,471	20,046,181	29.2	2.11%
477.01		CUSTOMER M&R EQUIPMENT	0	35-R3	0%	143,726,981	52,094,469	91,632,512	4,175,366	22.1	2.91%
478.00		METERS	0	25-L1.5	0%	1,020,910,894	469,525,898	551,384,996	28,777,649	17.3	2.82%
TOTAL DISTRIBUTION PLANT						**14,994,747,798**	**4,751,912,857**	**11,519,385,093**	**269,417,983**		1.80%

GENERAL PLANT										
482.00	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-R1.5	0%	13,255,572	8,677,610	4,577,962	119,585	32.3	0.90%
482.01	STRUCTURES AND IMPROVEMENTS - VPC	2033	40-R1.5	0%	53,463,354	19,270,729	34,192,626	3,290,400	10.3	6.15%
482.04	STRUCTURES AND IMPROVEMENTS - THOROLD	2022	40-R1.5	0%	15,678,640	6,391,978	9,286,662	9,286,662	0.5	59.23%
482.05	STRUCTURES AND IMPROVEMENTS - MARKHAM	2046	40-R1.5	0%	36,671,818	6,852,980	29,818,839	1,388,286	21.5	3.79%
482.51	STRUCTURES AND IMPROVEMENTS - KEIL HEAD OFFICE	2049	40-R1.5	0%	69,558,675	11,589,939	57,968,736	3,364,448	19.5	4.84%
482.52	STRUCTURES AND IMPROVEMENTS - BLOOMFIELD TRAINING CENTER	2028	40-R1.5	0%	19,237,692	1,664,764	17,572,928	2,783,764	6.3	14.47%
483.00	OFFICE FURNITURE AND EQUIPMENT	0	15-SQ	0%	29,776,062	20,323,396	9,452,666	1,309,316	6.0	4.40%
484.00	TRANSPORTATION EQUIPMENT	0	12-L2.5	0%	134,722,078	89,525,829	45,196,249	5,083,958	7.0	3.77%
485.00	HEAVY WORK EQUIPMENT	0	17-L1.5	0%	44,128,921	12,811,266	31,317,655	2,793,740	11.4	6.33%
486.00	TOOLS AND WORK EQUIPMENT	0	15-SQ	0%	79,966,854	26,128,214	53,838,641	9,529,666	7.6	11.92%
487.70	RENTAL - REFUEL APPL	0	15-SQ	0%	864,755	92,164	772,591	86,895	9.3	10.05%
487.80	RENTAL - NGV STATIONS	0	20-SQ	0%	7,774,175	2,397,143	5,377,032	291,548	18.4	3.75%
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	0	10-SQ	0%	11,224,609	4,990,530	6,234,079	2,946,627	2.6	26.25%
490.00	COMPUTER EQUIPMENT	0	4-SQ	0%	30,306,679	20,774,567	9,532,112	4,271,256	1.7	14.09%
	COMPUTER EQUIPMENT - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
490.30	COMPUTER EQUIPMENT - WAMS	0	10-SQ	0%	4,680,899	2,418,465	2,262,435	502,763	4.5	10.74%
491.01	SOFTWARE ACQUIRED INTANGIBLES	0	5-SQ	0%	155,164,785	107,550,337	47,614,448	10,697,136	3.0	6.89%
	SOFTWARE ACQUIRED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.02	SOFTWARE DEVELOPED INTANGIBLES	0	5-SQ	0%	38,776,288	25,519,357	13,256,930	3,058,684	3.2	7.89%
	SOFTWARE DEVELOPED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.03	CIS ACQUIRED SOFTWARE	0	10-SQ	0%	87,626,214	20,250,171	67,376,042	7,355,375	8.4	8.39%
**	SOFTWARE INTANGIBLES - 10 YEAR	0	10-SQ	0%	0	0	0	0	0.0	10.00%
491.04	WAMS	0	10-SQ	0%	85,221,905	44,031,318	41,190,587	9,153,464	4.5	10.74%
TOTAL GENERAL PLANT					**918,099,975**	**431,260,756**	**486,839,219**	**77,313,573**		8.42%
TOTAL UTILITY PLANT STUDIED					**21,693,291,183**	**7,125,714,397**	**16,098,934,463**	**446,318,453**		**2.06%**
PLANT NOT STUDIED										
401.00	Franchises and Consents - Total Comp				1,175,081					
402.04	Other Intangibles - Lakeland Acquisition Adjustment				494,761					
458.00	Base Pressure and Line Pack Gas				76,135,052					
	Land (Including MacLeod Property)				177,293,391					
	Plant Held for Future Use				1,670,861					
	Inventory Adjustment				59,309,971					
***	Post Study Adjustments				5,005,525					
TOTAL PLANT NOT STUDIED					**321,084,642**					
TOTAL UTILITY PLANT IN SERVICE					**22,014,375,825**					

* Annual Accrual Rates for new major structures in Account 472.00 after 2023 are 4.02%.
** New depreciation rate for major longer term intangible asset additions post 2023
*** Adjustments between regulated and unregulated storage operations to align with updated exhibits in Enbridge Gas's 2021 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding (EB-2022-0110), as filed on September 2, 2022

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021

Related to Total Expense

Account		Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LOCAL STORAGE PLANT											
442.00		STRUCTURES AND IMPROVEMENTS	0	40-S5	0%	6,282,181	2,805,060	3,477,121	104,018	25.1	1.66%
443.01		HOLDER - STORAGE TANK	0	45-R4	0%	5,804,412	4,023,544	1,780,869	51,698	20.5	0.89%
443.02		HOLDER EQUIPMENT	0	55-R4	0%	21,554,522	11,363,396	10,191,126	213,953	39.4	0.99%
TOTAL LOCAL STORAGE PLANT						**33,641,115**	**18,192,000**	**15,449,115**	**369,669**		1.10%
UNDERGROUND STORAGE PLANT											
451.00		LAND RIGHTS INTANGIBLE	0	55-R4	0%	74,762,354	45,841,825	28,920,529	1,070,227	24.9	1.43%
452.00		STRUCTURES AND IMPROVEMENTS	0	45-R2.5	0%	104,433,820	40,716,570	63,717,250	2,102,535	27.8	2.01%
453.00		WELLS	0	45-R2.5	0%	143,144,395	32,398,600	110,745,795	3,678,752	31.5	2.57%
454.00		WELL EQUIPMENT	0	40-R2	0%	13,364,517	8,575,936	4,788,581	134,706	26.6	1.01%
455.00		FIELD LINES	0	55-R3	0%	201,920,080	46,990,377	154,929,703	4,252,095	38.2	2.11%
456.00		COMPRESSOR EQUIPMENT	0	44-R4	0%	682,328,757	206,230,171	476,098,586	14,468,637	31.2	2.12%
457.00		REGULATING AND MEASURING EQUIPMENT	0	40-R2.5	0%	77,194,133	41,987,007	35,207,126	1,119,637	22.9	1.45%
TOTAL UNDERGROUND STORAGE PLANT						**1,297,148,055**	**422,740,485**	**874,407,570**	**26,826,589**		2.07%
TRANSMISSION PLANT											
461.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	88,171,402	20,599,533	67,571,869	1,409,557	47.6	1.60%
462.00		COMPRESSOR STRUCTURES AND IMPROVEMENTS	0	50-S4	0%	163,351,958	38,559,279	124,792,679	3,114,922	39.3	1.91%
463.00		MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	0	55-S4	0%	11,252,284	6,596,407	4,655,877	139,579	27.8	1.24%
464.00		EQUIPMENT	0	50-S4	0%	2,920,218	471,681	2,448,537	59,463	41.2	2.04%
465.00		MAINS	0	70-R4	0%	2,783,251,797	832,404,474	1,950,847,323	33,200,662	55.2	1.19%
466.00		COMPRESSOR EQUIPMENT	0	37-R4	0%	1,005,060,039	293,190,950	711,869,089	24,090,310	27.8	2.40%
467.00		MEASURING AND REGULATING EQUIPMENT	0	40-R4	0%	395,646,542	96,180,889	299,465,653	10,270,263	29.6	2.60%
TOTAL TRANSMISSION PLANT						**4,449,654,239**	**1,288,003,213**	**3,161,651,026**	**72,284,756**		1.62%
DISTRIBUTION PLANT											
471.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	63,907,560	12,099,619	51,807,941	1,072,013	48.4	1.68%
472.00	*	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-S0.5	0%	220,832,605	64,014,227	156,818,378	5,155,524	29.4	2.33%
472.31		STRUCTURES AND IMPROVEMENTS - STONEY CREEK	2046	40-S0.5	0%	29,662,115	5,056,171	24,605,944	1,180,276	20.8	3.98%
472.32		STRUCTURES AND IMPROVEMENTS - WIN-RHODES	2046	40-S0.5	0%	23,216,546	5,549,955	17,666,591	885,199	20.0	3.81%
472.33		STRUCTURES AND IMPROVEMENTS - LONDON ADMIN	2026	40-S0.5	0%	19,789,902	9,778,917	10,010,985	2,353,163	4.2	11.89%
472.34		STRUCTURES AND IMPROVEMENTS - KINGSTON OFFICE	2046	40-S0.5	0%	16,737,576	4,069,504	12,668,072	628,711	20.1	3.76%
472.35		STRUCTURES AND IMPROVEMENTS - MAINWAY	0	40-S0.5	0%	15,937,297	3,958,252	11,979,045	414,162	28.9	2.60%
473.01		SERVICES - METAL	0	50-L1	0%	549,648,294	157,755,963	391,892,331	8,745,501	36.2	1.59%
473.02		SERVICES - PLASTIC	0	60-S3	0%	4,458,883,265	990,047,894	3,468,835,371	79,349,017	44.0	1.78%
474.00		REGULATORS	0	50-L1	0%	488,870,931	59,858,893	429,012,038	10,172,494	42.3	2.08%
475.00		MAINS - ENVISION	0	25-SQ	0%	181,264,676	59,887,548	121,377,128	10,469,399	12.2	5.78%
475.21		MAINS - COATED & WRAPPED	0	70-R3	0%	3,320,418,328	591,728,974	2,728,689,354	46,125,241	54.6	1.39%
475.30		MAINS - PLASTIC	0	70-R2	0%	3,480,106,028	596,837,032	2,883,268,996	49,543,015	57.0	1.42%
476.00		COMPANY NGV COMPRESSOR STATIONS	0	17-S2.5	0%	9,878,703	5,181,735	4,696,968	325,072	10.9	3.29%
477.00		MEASURING AND REGULATING EQUIPMENT	0	40-R2	0%	950,956,098	335,072,893	615,883,205	19,826,592	29.2	2.08%
477.01		CUSTOMER M&R EQUIPMENT	0	35-R3	0%	143,726,981	52,094,469	91,632,512	4,175,366	22.1	2.91%
478.00		METERS	0	25-L1.5	0%	1,020,910,894	469,525,898	551,384,996	28,777,649	17.3	2.82%
TOTAL DISTRIBUTION PLANT						**14,994,747,798**	**3,422,517,944**	**11,572,229,854**	**269,198,394**		1.80%

GENERAL PLANT										
482.00	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-R1.5	0%	13,255,572	8,677,610	4,577,962	119,585	32.3	0.90%
482.01	STRUCTURES AND IMPROVEMENTS - VPC	2033	40-R1.5	0%	53,463,354	19,270,729	34,192,626	3,290,400	10.3	6.15%
482.04	STRUCTURES AND IMPROVEMENTS - THOROLD	2022	40-R1.5	0%	15,678,640	6,391,978	9,286,662	9,286,662	0.5	59.23%
482.05	STRUCTURES AND IMPROVEMENTS - MARKHAM	2046	40-R1.5	0%	36,671,818	6,852,980	29,818,839	1,388,286	21.5	3.79%
482.51	STRUCTURES AND IMPROVEMENTS - KEIL HEAD OFFICE	2049	40-R1.5	0%	69,558,675	11,589,939	57,968,736	3,364,448	19.5	4.84%
482.52	STRUCTURES AND IMPROVEMENTS - BLOOMFIELD TRAINING CENTER	2028	40-R1.5	0%	19,237,692	1,664,764	17,572,928	2,783,764	6.3	14.47%
483.00	OFFICE FURNITURE AND EQUIPMENT	0	15-SQ	0%	29,776,062	20,323,396	9,452,666	1,309,316	6.0	4.40%
484.00	TRANSPORTATION EQUIPMENT	0	12-L2.5	0%	134,722,078	89,525,829	45,196,249	5,083,958	7.0	3.77%
485.00	HEAVY WORK EQUIPMENT	0	17-L1.5	0%	44,128,921	12,811,266	31,317,655	2,793,740	11.4	6.33%
486.00	TOOLS AND WORK EQUIPMENT	0	15-SQ	0%	79,966,854	26,128,214	53,838,641	9,529,666	7.6	11.92%
487.70	RENTAL - REFUEL APPL	0	15-SQ	0%	864,755	92,164	772,591	86,895	9.3	10.05%
487.80	RENTAL - NGV STATIONS	0	20-SQ	0%	7,774,175	2,397,143	5,377,032	291,548	18.4	3.75%
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	0	10-SQ	0%	11,224,609	4,990,530	6,234,079	2,946,627	2.6	26.25%
490.00	COMPUTER EQUIPMENT	0	4-SQ	0%	30,306,679	20,774,567	9,532,112	4,271,256	1.7	14.09%
	COMPUTER EQUIPMENT - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	0.00%
490.30	COMPUTER EQUIPMENT - WAMS	0	10-SQ	0%	4,680,899	2,418,465	2,262,435	502,763	4.5	10.74%
491.01	SOFTWARE ACQUIRED INTANGIBLES	0	5-SQ	0%	155,164,785	107,550,337	47,614,448	10,697,136	3.0	6.89%
	SOFTWARE ACQUIRED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	0.00%
491.02	SOFTWARE DEVELOPED INTANGIBLES	0	5-SQ	0%	38,776,288	25,519,357	13,256,930	3,058,684	3.2	7.89%
	SOFTWARE DEVELOPED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	0.00%
491.03	CIS ACQUIRED SOFTWARE	0	10-SQ	0%	87,626,214	20,250,171	67,376,042	7,355,375	8.4	8.39%
**	SOFTWARE INTANGIBLES - 10 YEAR	0	10-SQ	0%	0	0	0	0	0.0	0.00%
491.04	WAMS	0	10-SQ	0%	85,221,905	44,031,318	41,190,587	9,153,464	4.5	10.74%
TOTAL GENERAL PLANT					**918,099,975**	**431,260,756**	**486,839,219**	**77,313,573**		8.42%
TOTAL UTILITY PLANT STUDIED					**21,693,291,183**	**5,582,714,398**	**16,110,576,785**	**445,992,981**		**2.06%**
PLANT NOT STUDIED										
401.00	Franchises and Consents - Total Comp				1,175,081					
402.04	Other Intangibles - Lakeland Acquisition Adjustment				494,761					
458.00	Base Pressure and Line Pack Gas				76,135,052					
	Land (Including MacLeod Property)				177,293,391					
	Plant Held for Future Use				1,670,861					
	Inventory Adjustment				59,309,971					
***	Post Study Adjustments				5,005,525					
TOTAL PLANT NOT STUDIED					**321,084,642**					
TOTAL UTILITY PLANT IN SERVICE					**22,014,375,825**					

* Annual Accrual Rates for new major structures in Account 472.00 after 2023 are 4.02%.
** New depreciation rate for major longer term intangible asset additions post 2023
*** Adjustments between regulated and unregulated storage operations to align with updated exhibits in Enbridge Gas's 2021 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding (EB-2022-0110), as filed on September 2, 2022

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021

Related to Total Expense

Account		Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LOCAL STORAGE PLANT											
442.00		STRUCTURES AND IMPROVEMENTS	0	40-S5	0%	6,282,181	0	6,282,181	0	0.0	0.00%
443.01		HOLDER - STORAGE TANK	0	45-R4	0%	5,804,412	0	5,804,412	0	0.0	0.00%
443.02		HOLDER EQUIPMENT	0	55-R4	0%	21,554,522	0	21,554,522	0	0.0	0.00%
TOTAL LOCAL STORAGE PLANT						**33,641,115**	**0**	**33,641,115**	**0**		0.00%
UNDERGROUND STORAGE PLANT											
451.00		LAND RIGHTS INTANGIBLE	0	55-R4	0%	74,762,354	0	74,762,354	0	0.0	0.00%
452.00		STRUCTURES AND IMPROVEMENTS	0	45-R2.5	-6%	104,433,820	6,431,462	104,268,388	0	0.0	0.00%
453.00		WELLS	0	45-R2.5	-16%	143,144,395	17,641,940	148,405,558	0	0.0	0.00%
454.00		WELL EQUIPMENT	0	40-R2	0%	13,364,517	0	13,364,517	0	0.0	0.00%
455.00		FIELD LINES	0	55-R3	-4%	201,920,080	6,307,738	203,689,145	0	0.0	0.00%
456.00		COMPRESSOR EQUIPMENT	0	44-R4	-3%	682,328,757	22,081,025	680,717,595	0	0.0	0.00%
457.00		REGULATING AND MEASURING EQUIPMENT	0	40-R2.5	-8%	77,194,133	9,842,821	73,526,843	0	0.0	0.00%
TOTAL UNDERGROUND STORAGE PLANT						**1,297,148,055**	**62,304,985**	**1,298,734,399**	**0**		0.00%
TRANSMISSION PLANT											
461.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	88,171,402	0	88,171,402	0	0.0	0.00%
462.00		COMPRESSOR STRUCTURES AND IMPROVEMENTS	0	50-S4	-2%	163,351,958	1,794,352	164,824,646	18,429	0.0	0.01%
463.00		MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	0	55-S4	-4%	11,252,284	570,861	11,131,514	0	0.0	0.00%
464.00		EQUIPMENT	0	50-S4	-2%	2,920,218	51,961	2,926,661	0	0.0	0.00%
465.00		MAINS	0	70-R4	-4%	2,783,251,797	86,925,673	2,807,656,196	70,811	0.0	0.00%
466.00		COMPRESSOR EQUIPMENT	0	37-R4	-4%	1,005,060,039	38,339,632	1,006,922,809	0	0.0	0.00%
467.00		MEASURING AND REGULATING EQUIPMENT	0	40-R4	-9%	395,646,542	23,617,623	407,637,108	16,643	0.0	0.00%
TOTAL TRANSMISSION PLANT						**4,449,654,239**	**151,300,101**	**4,489,270,335**	**105,883**		0.00%
DISTRIBUTION PLANT											
471.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	63,907,560	0	63,907,560	0	0.0	0.00%
472.00	*	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-S0.5	0%	220,832,605	0	220,832,605	0	0.0	0.00%
472.31		STRUCTURES AND IMPROVEMENTS - STONEY CREEK	2046	40-S0.5	0%	29,662,115	0	29,662,115	0	0.0	0.00%
472.32		STRUCTURES AND IMPROVEMENTS - WIN-RHODES	2046	40-S0.5	0%	23,216,546	0	23,216,546	0	0.0	0.00%
472.33		STRUCTURES AND IMPROVEMENTS - LONDON ADMIN	2026	40-S0.5	0%	19,789,902	0	19,789,902	0	0.0	0.00%
472.34		STRUCTURES AND IMPROVEMENTS - KINGSTON OFFICE	2046	40-S0.5	0%	16,737,576	0	16,737,576	0	0.0	0.00%
472.35		STRUCTURES AND IMPROVEMENTS - MAINWAY	0	40-S0.5	0%	15,937,297	0	15,937,297	0	0.0	0.00%
473.01		SERVICES - METAL	0	50-L1	-13%	549,648,294	110,569,852	510,532,721	0	0.0	0.00%
473.02		SERVICES - PLASTIC	0	60-S3	-10%	4,458,883,265	394,785,610	4,509,985,982	0	0.0	0.00%
474.00		REGULATORS	0	50-L1	0%	488,870,931	0	488,870,931	0	0.0	0.00%
475.00		MAINS - ENVISION	0	25-SQ	0%	181,264,676	0	181,264,676	0	0.0	0.00%
475.21		MAINS - COATED & WRAPPED	0	70-R3	-12%	3,320,418,328	459,630,062	3,259,238,466	0	0.0	0.00%
475.30		MAINS - PLASTIC	0	70-R2	-9%	3,480,106,028	331,594,851	3,461,720,720	0	0.0	0.00%
476.00		COMPANY NGV COMPRESSOR STATIONS	0	17-S2.5	0%	9,878,703	0	9,878,703	0	0.0	0.00%
477.00		MEASURING AND REGULATING EQUIPMENT	0	40-R2	-5%	950,956,098	32,814,539	965,689,364	219,589	0.0	0.02%
477.01		CUSTOMER M&R EQUIPMENT	0	35-R3	0%	143,726,981	0	143,726,981	0	0.0	0.00%
478.00		METERS	0	25-L1.5	0%	1,020,910,894	0	1,020,910,894	0	0.0	0.00%
TOTAL DISTRIBUTION PLANT						**14,994,747,798**	**1,329,394,913**	**14,941,903,037**	**219,589**		0.00%

GENERAL PLANT										
482.00	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-R1.5	0%	13,255,572	0	13,255,572	0	0.0	0.00%
482.01	STRUCTURES AND IMPROVEMENTS - VPC	2033	40-R1.5	0%	53,463,354	0	53,463,354	0	0.0	0.00%
482.04	STRUCTURES AND IMPROVEMENTS - THOROLD	2022	40-R1.5	0%	15,678,640	0	15,678,640	0	0.0	0.00%
482.05	STRUCTURES AND IMPROVEMENTS - MARKHAM	2046	40-R1.5	0%	36,671,818	0	36,671,818	0	0.0	0.00%
482.51	STRUCTURES AND IMPROVEMENTS - KEIL HEAD OFFICE	2049	40-R1.5	0%	69,558,675	0	69,558,675	0	0.0	0.00%
482.52	STRUCTURES AND IMPROVEMENTS - BLOOMFIELD TRAINING CENTER	2028	40-R1.5	0%	19,237,692	0	19,237,692	0	0.0	0.00%
483.00	OFFICE FURNITURE AND EQUIPMENT	0	15-SQ	0%	29,776,062	0	29,776,062	0	0.0	0.00%
484.00	TRANSPORTATION EQUIPMENT	0	12-L2.5	0%	134,722,078	0	134,722,078	0	0.0	0.00%
485.00	HEAVY WORK EQUIPMENT	0	17-L1.5	0%	44,128,921	0	44,128,921	0	0.0	0.00%
486.00	TOOLS AND WORK EQUIPMENT	0	15-SQ	0%	79,966,854	0	79,966,854	0	0.0	0.00%
487.70	RENTAL - REFUEL APPL	0	15-SQ	0%	864,755	0	864,755	0	0.0	0.00%
487.80	RENTAL - NGV STATIONS	0	20-SQ	0%	7,774,175	0	7,774,175	0	0.0	0.00%
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	0	10-SQ	0%	11,224,609	0	11,224,609	0	0.0	0.00%
490.00	COMPUTER EQUIPMENT	0	4-SQ	0%	30,306,679	0	30,306,679	0	0.0	0.00%
	COMPUTER EQUIPMENT - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
490.30	COMPUTER EQUIPMENT - WAMS	0	10-SQ	0%	4,680,899	0	4,680,899	0	0.0	0.00%
491.01	SOFTWARE ACQUIRED INTANGIBLES	0	5-SQ	0%	155,164,785	0	155,164,785	0	0.0	0.00%
	SOFTWARE ACQUIRED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.02	SOFTWARE DEVELOPED INTANGIBLES	0	5-SQ	0%	38,776,288	0	38,776,288	0	0.0	0.00%
	SOFTWARE DEVELOPED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.03	CIS ACQUIRED SOFTWARE	0	10-SQ	0%	87,626,214	0	87,626,214	0	0.0	0.00%
**	SOFTWARE INTANGIBLES - 10 YEAR	0	10-SQ	0%	0	0	0	0	0.0	10.00%
491.04	WAMS	0	10-SQ	0%	85,221,905	0	85,221,905	0	0.0	0.00%
TOTAL GENERAL PLANT					**918,099,975**	**0**	**918,099,975**	**0**		0.00%
TOTAL UTILITY PLANT STUDIED					**21,693,291,183**	**1,542,999,999**	**21,681,648,861**	**325,472**		**0.00%**
PLANT NOT STUDIED										
401.00	Franchises and Consents - Total Comp				1,175,081					
402.04	Other Intangibles - Lakeland Acquisition Adjustment				494,761					
458.00	Base Pressure and Line Pack Gas				76,135,052					
	Land (Including MacLeod Property)				177,293,391					
	Plant Held for Future Use				1,670,861					
	Inventory Adjustment				59,309,971					
***	Post Study Adjustments				5,005,525					
TOTAL PLANT NOT STUDIED					**321,084,642**					
TOTAL UTILITY PLANT IN SERVICE					**22,014,375,825**					

* Annual Accrual Rates for new major structures in Account 472.00 after 2023 are 4.02%.
** New depreciation rate for major longer term intangible asset additions post 2023
*** Adjustments between regulated and unregulated storage operations to align with updated exhibits in Enbridge Gas's 2021 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding (EB-2022-0110), as filed on September 2, 2022

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021

Related to Total Expense

Account		Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LOCAL STORAGE PLANT											
442.00		STRUCTURES AND IMPROVEMENTS	0	40-S5	0%	6,282,181	2,805,060	3,477,121	104,018	25.1	1.66%
443.01		HOLDER - STORAGE TANK	0	45-R4	0%	5,804,412	4,023,544	1,780,869	51,698	20.5	0.89%
443.02		HOLDER EQUIPMENT	0	55-R4	0%	21,554,522	11,363,396	10,191,126	213,953	39.4	0.99%
TOTAL LOCAL STORAGE PLANT						**33,641,115**	**18,192,000**	**15,449,115**	**369,669**		1.10%
UNDERGROUND STORAGE PLANT											
451.00		LAND RIGHTS INTANGIBLE	0	55-R4	0%	74,762,354	45,841,825	28,920,529	1,070,227	24.9	1.43%
452.00		STRUCTURES AND IMPROVEMENTS	0	45-R3	-6%	104,433,820	47,148,032	63,551,818	2,184,434	27.0	2.09%
453.00		WELLS	0	45-R2.5	-16%	143,144,395	50,040,540	116,006,958	3,678,752	31.5	2.57%
454.00		WELL EQUIPMENT	0	40-R2	0%	13,364,517	8,575,936	4,788,581	134,706	26.6	1.01%
455.00		FIELD LINES	0	55-R3	-4%	201,920,080	53,298,115	156,698,768	4,252,095	38.2	2.11%
456.00		COMPRESSOR EQUIPMENT	0	40-R4	-4%	682,328,757	228,311,196	481,310,711	17,323,927	27.4	2.54%
457.00		REGULATING AND MEASURING EQUIPMENT	0	35-R3	-10%	77,194,133	51,829,828	33,083,719	1,544,558	17.6	2.00%
TOTAL UNDERGROUND STORAGE PLANT						**1,297,148,055**	**485,045,470**	**884,361,084**	**30,188,699**		2.33%
TRANSMISSION PLANT											
461.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	88,171,402	20,599,533	67,571,869	1,409,557	47.6	1.60%
462.00		COMPRESSOR STRUCTURES AND IMPROVEMENTS	0	50-S4	-2%	163,351,958	40,353,631	126,265,367	3,133,351	39.3	1.92%
463.00		MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	0	55-S4	-4%	11,252,284	7,167,268	4,535,107	139,579	27.8	1.24%
464.00		EQUIPMENT	0	30-L0.5	-4%	2,920,218	523,642	2,513,384	101,439	24.8	3.47%
465.00		MAINS	0	60-R4	-5%	2,783,251,797	919,330,147	2,003,084,240	41,049,411	45.4	1.47%
466.00		COMPRESSOR EQUIPMENT	0	30-R4	-5%	1,005,060,039	331,530,582	723,782,459	33,201,298	21.1	3.30%
467.00		MEASURING AND REGULATING EQUIPMENT	0	40-R4	-9%	395,646,542	119,798,512	311,456,219	10,286,906	29.6	2.60%
TOTAL TRANSMISSION PLANT						**4,449,654,239**	**1,439,303,314**	**3,239,208,644**	**89,321,541**		2.01%
DISTRIBUTION PLANT											
471.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	63,907,560	12,099,619	51,807,941	1,072,013	48.4	1.68%
472.00	*	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-S0.5	0%	220,832,605	64,014,227	156,818,378	5,155,524	29.4	2.33%
472.31		STRUCTURES AND IMPROVEMENTS - STONEY CREEK	2046	40-S0.5	0%	29,662,115	5,056,171	24,605,944	1,180,276	20.8	3.98%
472.32		STRUCTURES AND IMPROVEMENTS - WIN-RHODES	2046	40-S0.5	0%	23,216,546	5,549,955	17,666,591	885,199	20.0	3.81%
472.33		STRUCTURES AND IMPROVEMENTS - LONDON ADMIN	2026	40-S0.5	0%	19,789,902	9,778,917	10,010,985	2,353,163	4.2	11.89%
472.34		STRUCTURES AND IMPROVEMENTS - KINGSTON OFFICE	2046	40-S0.5	0%	16,737,576	4,069,504	12,668,072	628,711	20.1	3.76%
472.35		STRUCTURES AND IMPROVEMENTS - MAINWAY	2027	40-S0.5	0%	15,937,297	3,958,252	11,979,045	2,247,542	5.3	14.10%
473.01		SERVICES - METAL	0	40-S0.5	-21%	549,648,294	268,325,815	396,748,621	14,923,457	25.0	2.72%
473.02		SERVICES - PLASTIC	0	55-S3	-12%	4,458,883,265	1,384,833,504	3,609,115,753	92,643,308	39.2	2.08%
474.00		REGULATORS	0	25-SQ	0%	488,870,931	59,858,893	429,012,038	43,329,780	15.5	8.86%
475.00		MAINS - ENVISION	0	25-SQ	0%	181,264,676	59,887,548	121,377,128	10,469,399	12.2	5.78%
475.21		MAINS - COATED & WRAPPED	0	55-R3	-20%	3,320,418,328	1,051,359,036	2,933,142,958	73,793,663	40.1	2.22%
475.30		MAINS - PLASTIC	0	60-R4	-15%	3,480,106,028	928,431,883	3,073,690,049	68,594,099	45.1	1.97%
476.00		COMPANY NGV COMPRESSOR STATIONS	0	17-S2.5	0%	9,878,703	5,181,735	4,696,968	325,072	10.9	3.29%
477.00		MEASURING AND REGULATING EQUIPMENT	0	40-R2	-5%	950,956,098	367,887,432	630,616,471	20,046,181	29.2	2.11%
477.01		CUSTOMER M&R EQUIPMENT	0	35-R3	0%	143,726,981	52,094,469	91,632,512	4,175,366	22.1	2.91%
478.00		METERS	0	15-S2.5	0%	1,020,910,894	469,525,898	551,384,996	91,419,431	7.2	8.95%
TOTAL DISTRIBUTION PLANT						**14,994,747,798**	**4,751,912,857**	**12,126,974,450**	**433,242,184**		2.89%

GENERAL PLANT										
482.00	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-R1.5	0%	13,255,572	8,677,610	4,577,962	119,585	32.3	0.90%
482.01	STRUCTURES AND IMPROVEMENTS - VPC	2033	40-R1.5	0%	53,463,354	19,270,729	34,192,626	3,290,400	10.3	6.15%
482.04	STRUCTURES AND IMPROVEMENTS - THOROLD	2022	40-R1.5	0%	15,678,640	6,391,978	9,286,662	9,286,662	0.5	59.23%
482.05	STRUCTURES AND IMPROVEMENTS - MARKHAM	2046	40-R1.5	0%	36,671,818	6,852,980	29,818,839	1,388,286	21.5	3.79%
482.51	STRUCTURES AND IMPROVEMENTS - KEIL HEAD OFFICE	2049	40-R1.5	0%	69,558,675	11,589,939	57,968,736	3,364,448	19.5	4.84%
482.52	STRUCTURES AND IMPROVEMENTS - BLOOMFIELD TRAINING CENTER	2028	40-R1.5	0%	19,237,692	1,664,764	17,572,928	2,783,764	6.3	14.47%
483.00	OFFICE FURNITURE AND EQUIPMENT	0	15-SQ	0%	29,776,062	20,323,396	9,452,666	1,309,316	6.0	4.40%
484.00	TRANSPORTATION EQUIPMENT	0	12-L2.5	0%	134,722,078	89,525,829	45,196,249	5,083,958	7.0	3.77%
485.00	HEAVY WORK EQUIPMENT	0	17-L1.5	0%	44,128,921	12,811,266	31,317,655	2,793,740	11.4	6.33%
486.00	TOOLS AND WORK EQUIPMENT	0	15-SQ	0%	79,966,854	26,128,214	53,838,641	9,529,666	7.6	11.92%
487.70	RENTAL - REFUEL APPL	0	15-SQ	0%	864,755	92,164	772,591	86,895	9.3	10.05%
487.80	RENTAL - NGV STATIONS	0	20-SQ	0%	7,774,175	2,397,143	5,377,032	291,548	18.4	3.75%
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	0	10-SQ	0%	11,224,609	4,990,530	6,234,079	2,946,627	2.6	26.25%
490.00	COMPUTER EQUIPMENT	0	4-SQ	0%	30,306,679	20,774,567	9,532,112	4,271,256	1.7	14.09%
	COMPUTER EQUIPMENT - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
490.30	COMPUTER EQUIPMENT - WAMS	0	10-SQ	0%	4,680,899	2,418,465	2,262,435	502,763	4.5	10.74%
491.01	SOFTWARE ACQUIRED INTANGIBLES	0	4-SQ	0%	155,164,785	107,550,337	47,614,448	13,823,969	2.0	8.91%
	SOFTWARE ACQUIRED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.02	SOFTWARE DEVELOPED INTANGIBLES	0	4-SQ	0%	38,776,288	25,519,357	13,256,930	3,990,552	2.2	10.29%
	SOFTWARE DEVELOPED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.03	CIS ACQUIRED SOFTWARE	0	10-SQ	0%	87,626,214	20,250,171	67,376,042	7,355,375	8.4	8.39%
**	SOFTWARE INTANGIBLES - 10 YEAR	0	10-SQ	0%	0	0	0	0	0.0	10.00%
491.04	WAMS	0	10-SQ	0%	85,221,905	44,031,318	41,190,587	9,153,464	4.5	10.74%
TOTAL GENERAL PLANT					**918,099,975**	**431,260,756**	**486,839,219**	**81,372,274**		8.86%
TOTAL UTILITY PLANT STUDIED					**21,693,291,183**	**7,125,714,397**	**16,752,832,513**	**634,494,367**		**2.92%**
PLANT NOT STUDIED										
401.00	Franchises and Consents - Total Comp				1,175,081					
402.04	Other Intangibles - Lakeland Acquisition Adjustment				494,761					
458.00	Base Pressure and Line Pack Gas				76,135,052					
	Land (Including MacLeod Property)				177,293,391					
	Plant Held for Future Use				1,670,861					
	Inventory Adjustment				59,309,971					
***	Post Study Adjustments				5,005,525					
TOTAL PLANT NOT STUDIED					**321,084,642**					
TOTAL UTILITY PLANT IN SERVICE					**22,014,375,825**					

* Annual Accrual Rates for new major structures in Account 472.00 after 2023 are 4.02%.
** New depreciation rate for major longer term intangible asset additions post 2023
*** Adjustments between regulated and unregulated storage operations to align with updated exhibits in Enbridge Gas's 2021 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding (EB-2022-0110), as filed on September 2, 2022

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021

Related to Total Expense

Account		Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LOCAL STORAGE PLANT											
442.00		STRUCTURES AND IMPROVEMENTS	0	40-S5	0%	6,282,181	2,805,060	3,477,121	104,018	25.1	1.66%
443.01		HOLDER - STORAGE TANK	0	45-R4	0%	5,804,412	4,023,544	1,780,869	51,698	20.5	0.89%
443.02		HOLDER EQUIPMENT	0	55-R4	0%	21,554,522	11,363,396	10,191,126	213,953	39.4	0.99%
TOTAL LOCAL STORAGE PLANT						**33,641,115**	**18,192,000**	**15,449,115**	**369,669**		1.10%
UNDERGROUND STORAGE PLANT											
451.00		LAND RIGHTS INTANGIBLE	0	55-R4	0%	74,762,354	45,841,825	28,920,529	1,070,227	24.9	1.43%
452.00		STRUCTURES AND IMPROVEMENTS	0	45-R3	0%	104,433,820	40,716,570	63,717,250	2,184,434	27.0	2.09%
453.00		WELLS	0	45-R2.5	0%	143,144,395	32,398,600	110,745,795	3,678,752	31.5	2.57%
454.00		WELL EQUIPMENT	0	40-R2	0%	13,364,517	8,575,936	4,788,581	134,706	26.6	1.01%
455.00		FIELD LINES	0	55-R3	0%	201,920,080	46,990,377	154,929,703	4,252,095	38.2	2.11%
456.00		COMPRESSOR EQUIPMENT	0	40-R4	0%	682,328,757	206,230,171	476,098,586	17,323,927	27.4	2.54%
457.00		REGULATING AND MEASURING EQUIPMENT	0	35-R3	0%	77,194,133	41,987,007	35,207,126	1,544,558	17.6	2.00%
TOTAL UNDERGROUND STORAGE PLANT						**1,297,148,055**	**422,740,485**	**874,407,570**	**30,188,699**		2.33%
TRANSMISSION PLANT											
461.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	88,171,402	20,599,533	67,571,869	1,409,557	47.6	1.60%
462.00		COMPRESSOR STRUCTURES AND IMPROVEMENTS	0	50-S4	0%	163,351,958	38,559,279	124,792,679	3,114,922	39.3	1.91%
463.00		MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	0	55-S4	0%	11,252,284	6,596,407	4,655,877	139,579	27.8	1.24%
464.00		EQUIPMENT	0	30-L0.5	0%	2,920,218	471,681	2,448,537	99,376	24.8	3.40%
465.00		MAINS	0	60-R4	0%	2,783,251,797	832,404,474	1,950,847,323	40,464,871	45.4	1.45%
466.00		COMPRESSOR EQUIPMENT	0	30-R4	0%	1,005,060,039	293,190,950	711,869,089	33,201,298	21.1	3.30%
467.00		MEASURING AND REGULATING EQUIPMENT	0	40-R4	0%	395,646,542	96,180,889	299,465,653	10,270,263	29.6	2.60%
TOTAL TRANSMISSION PLANT						**4,449,654,239**	**1,288,003,213**	**3,161,651,026**	**88,699,866**		1.99%
DISTRIBUTION PLANT											
471.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	63,907,560	12,099,619	51,807,941	1,072,013	48.4	1.68%
472.00	*	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-S0.5	0%	220,832,605	64,014,227	156,818,378	5,155,524	29.4	2.33%
472.31		STRUCTURES AND IMPROVEMENTS - STONEY CREEK	2046	40-S0.5	0%	29,662,115	5,056,171	24,605,944	1,180,276	20.8	3.98%
472.32		STRUCTURES AND IMPROVEMENTS - WIN-RHODES	2046	40-S0.5	0%	23,216,546	5,549,955	17,666,591	885,199	20.0	3.81%
472.33		STRUCTURES AND IMPROVEMENTS - LONDON ADMIN	2026	40-S0.5	0%	19,789,902	9,778,917	10,010,985	2,353,163	4.2	11.89%
472.34		STRUCTURES AND IMPROVEMENTS - KINGSTON OFFICE	2046	40-S0.5	0%	16,737,576	4,069,504	12,668,072	628,711	20.1	3.76%
472.35		STRUCTURES AND IMPROVEMENTS - MAINWAY	2027	40-S0.5	0%	15,937,297	3,958,252	11,979,045	2,247,542	5.3	14.10%
473.01		SERVICES - METAL	0	40-S0.5	0%	549,648,294	157,755,963	391,892,331	14,923,457	25.0	2.72%
473.02		SERVICES - PLASTIC	0	55-S3	0%	4,458,883,265	990,047,894	3,468,835,371	91,294,906	39.2	2.05%
474.00		REGULATORS	0	25-SQ	0%	488,870,931	59,858,893	429,012,038	43,329,780	15.5	8.86%
475.00		MAINS - ENVISION	0	25-SQ	0%	181,264,676	59,887,548	121,377,128	10,469,399	12.2	5.78%
475.21		MAINS - COATED & WRAPPED	0	55-R3	0%	3,320,418,328	591,728,974	2,728,689,354	73,793,663	40.1	2.22%
475.30		MAINS - PLASTIC	0	60-R4	0%	3,480,106,028	596,837,032	2,883,268,996	65,904,818	45.1	1.89%
476.00		COMPANY NGV COMPRESSOR STATIONS	0	17-S2.5	0%	9,878,703	5,181,735	4,696,968	325,072	10.9	3.29%
477.00		MEASURING AND REGULATING EQUIPMENT	0	40-R2	0%	950,956,098	335,072,893	615,883,205	19,826,592	29.2	2.08%
477.01		CUSTOMER M&R EQUIPMENT	0	35-R3	0%	143,726,981	52,094,469	91,632,512	4,175,366	22.1	2.91%
478.00		METERS	0	15-S2.5	0%	1,020,910,894	469,525,898	551,384,996	91,419,431	7.2	8.95%
TOTAL DISTRIBUTION PLANT						**14,994,747,798**	**3,422,517,944**	**11,572,229,854**	**428,984,912**		2.86%

GENERAL PLANT										
482.00	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-R1.5	0%	13,255,572	8,677,610	4,577,962	119,585	32.3	0.90%
482.01	STRUCTURES AND IMPROVEMENTS - VPC	2033	40-R1.5	0%	53,463,354	19,270,729	34,192,626	3,290,400	10.3	6.15%
482.04	STRUCTURES AND IMPROVEMENTS - THOROLD	2022	40-R1.5	0%	15,678,640	6,391,978	9,286,662	9,286,662	0.5	59.23%
482.05	STRUCTURES AND IMPROVEMENTS - MARKHAM	2046	40-R1.5	0%	36,671,818	6,852,980	29,818,839	1,388,286	21.5	3.79%
482.51	STRUCTURES AND IMPROVEMENTS - KEIL HEAD OFFICE	2049	40-R1.5	0%	69,558,675	11,589,939	57,968,736	3,364,448	19.5	4.84%
482.52	STRUCTURES AND IMPROVEMENTS - BLOOMFIELD TRAINING CENTER	2028	40-R1.5	0%	19,237,692	1,664,764	17,572,928	2,783,764	6.3	14.47%
483.00	OFFICE FURNITURE AND EQUIPMENT	0	15-SQ	0%	29,776,062	20,323,396	9,452,666	1,309,316	6.0	4.40%
484.00	TRANSPORTATION EQUIPMENT	0	12-L2.5	0%	134,722,078	89,525,829	45,196,249	5,083,958	7.0	3.77%
485.00	HEAVY WORK EQUIPMENT	0	17-L1.5	0%	44,128,921	12,811,266	31,317,655	2,793,740	11.4	6.33%
486.00	TOOLS AND WORK EQUIPMENT	0	15-SQ	0%	79,966,854	26,128,214	53,838,641	9,529,666	7.6	11.92%
487.70	RENTAL - REFUEL APPL	0	15-SQ	0%	864,755	92,164	772,591	86,895	9.3	10.05%
487.80	RENTAL - NGV STATIONS	0	20-SQ	0%	7,774,175	2,397,143	5,377,032	291,548	18.4	3.75%
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	0	10-SQ	0%	11,224,609	4,990,530	6,234,079	2,946,627	2.6	26.25%
490.00	COMPUTER EQUIPMENT	0	4-SQ	0%	30,306,679	20,774,567	9,532,112	4,271,256	1.7	14.09%
	COMPUTER EQUIPMENT - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	
490.30	COMPUTER EQUIPMENT - WAMS	0	10-SQ	0%	4,680,899	2,418,465	2,262,435	502,763	4.5	10.74%
491.01	SOFTWARE ACQUIRED INTANGIBLES	0	4-SQ	0%	155,164,785	107,550,337	47,614,448	13,823,969	2.0	8.91%
	SOFTWARE ACQUIRED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	
491.02	SOFTWARE DEVELOPED INTANGIBLES	0	4-SQ	0%	38,776,288	25,519,357	13,256,930	3,990,552	2.2	10.29%
	SOFTWARE DEVELOPED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	
491.03	CIS ACQUIRED SOFTWARE	0	10-SQ	0%	87,626,214	20,250,171	67,376,042	7,355,375	8.4	8.39%
**	SOFTWARE INTANGIBLES - 10 YEAR	0	10-SQ	0%	0	0	0	0	0.0	
491.04	WAMS	0	10-SQ	0%	85,221,905	44,031,318	41,190,587	9,153,464	4.5	10.74%
TOTAL GENERAL PLANT					**918,099,975**	**431,260,756**	**486,839,219**	**81,372,274**		8.86%
TOTAL UTILITY PLANT STUDIED					**21,693,291,183**	**5,582,714,398**	**16,110,576,785**	**629,615,420**		**2.90%**
PLANT NOT STUDIED										
401.00	Franchises and Consents - Total Comp				1,175,081					
402.04	Other Intangibles - Lakeland Acquisition Adjustment				494,761					
458.00	Base Pressure and Line Pack Gas				76,135,052					
	Land (Including MacLeod Property)				177,293,391					
	Plant Held for Future Use				1,670,861					
	Inventory Adjustment				59,309,971					
***	Post Study Adjustments				5,005,525					
TOTAL PLANT NOT STUDIED					**321,084,642**					
TOTAL UTILITY PLANT IN SERVICE					**22,014,375,825**					

* Annual Accrual Rates for new major structures in Account 472.00 after 2023 are 4.02%.
** New depreciation rate for major longer term intangible asset additions post 2023
*** Adjustments between regulated and unregulated storage operations to align with updated exhibits in Enbridge Gas's 2021 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding (EB-2022-0110), as filed on September 2, 2022

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

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CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021

Related to Total Expense

Account		Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LOCAL STORAGE PLANT											
442.00		STRUCTURES AND IMPROVEMENTS	0	40-S5	0%	6,282,181	0	6,282,181	0	0.0	0.00%
443.01		HOLDER - STORAGE TANK	0	45-R4	0%	5,804,412	0	5,804,412	0	0.0	0.00%
443.02		HOLDER EQUIPMENT	0	55-R4	0%	21,554,522	0	21,554,522	0	0.0	0.00%
TOTAL LOCAL STORAGE PLANT						**33,641,115**	**0**	**33,641,115**	**0**		0.00%
UNDERGROUND STORAGE PLANT											
451.00		LAND RIGHTS INTANGIBLE	0	55-R4	0%	74,762,354	0	74,762,354	0	0.0	0.00%
452.00		STRUCTURES AND IMPROVEMENTS	0	45-R3	-6%	104,433,820	6,431,462	104,268,388	0	0.0	0.00%
453.00		WELLS	0	45-R2.5	-16%	143,144,395	17,641,940	148,405,558	0	0.0	0.00%
454.00		WELL EQUIPMENT	0	40-R2	0%	13,364,517	0	13,364,517	0	0.0	0.00%
455.00		FIELD LINES	0	55-R3	-4%	201,920,080	6,307,738	203,689,145	0	0.0	0.00%
456.00		COMPRESSOR EQUIPMENT	0	40-R4	-4%	682,328,757	22,081,025	687,540,882	0	0.0	0.00%
457.00		REGULATING AND MEASURING EQUIPMENT	0	35-R3	-10%	77,194,133	9,842,821	75,070,726	0	0.0	0.00%
TOTAL UNDERGROUND STORAGE PLANT						**1,297,148,055**	**62,304,985**	**1,307,101,569**	**0**		0.00%
TRANSMISSION PLANT											
461.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	88,171,402	0	88,171,402	0	0.0	0.00%
462.00		COMPRESSOR STRUCTURES AND IMPROVEMENTS	0	50-S4	-2%	163,351,958	1,794,352	164,824,646	18,429	0.0	0.01%
463.00		MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	0	55-S4	-4%	11,252,284	570,861	11,131,514	0	0.0	0.00%
464.00		EQUIPMENT	0	30-L0.5	-4%	2,920,218	51,961	2,985,065	2,063	0.0	0.07%
465.00		MAINS	0	60-R4	-5%	2,783,251,797	86,925,673	2,835,488,714	584,540	0.0	0.02%
466.00		COMPRESSOR EQUIPMENT	0	30-R4	-5%	1,005,060,039	38,339,632	1,016,973,409	0	0.0	0.00%
467.00		MEASURING AND REGULATING EQUIPMENT	0	40-R4	-9%	395,646,542	23,617,623	407,637,108	16,643	0.0	0.00%
TOTAL TRANSMISSION PLANT						**4,449,654,239**	**151,300,101**	**4,527,211,857**	**621,675**		0.01%
DISTRIBUTION PLANT											
471.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	63,907,560	0	63,907,560	0	0.0	0.00%
472.00	*	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-S0.5	0%	220,832,605	0	220,832,605	0	0.0	0.00%
472.31		STRUCTURES AND IMPROVEMENTS - STONEY CREEK	2046	40-S0.5	0%	29,662,115	0	29,662,115	0	0.0	0.00%
472.32		STRUCTURES AND IMPROVEMENTS - WIN-RHODES	2046	40-S0.5	0%	23,216,546	0	23,216,546	0	0.0	0.00%
472.33		STRUCTURES AND IMPROVEMENTS - LONDON ADMIN	2026	40-S0.5	0%	19,789,902	0	19,789,902	0	0.0	0.00%
472.34		STRUCTURES AND IMPROVEMENTS - KINGSTON OFFICE	2046	40-S0.5	0%	16,737,576	0	16,737,576	0	0.0	0.00%
472.35		STRUCTURES AND IMPROVEMENTS - MAINWAY	2027	40-S0.5	0%	15,937,297	0	15,937,297	0	0.0	0.00%
473.01		SERVICES - METAL	0	40-S0.5	-21%	549,648,294	110,569,852	554,504,584	0	0.0	0.00%
473.02		SERVICES - PLASTIC	0	55-S3	-12%	4,458,883,265	394,785,610	4,599,163,647	1,348,402	0.0	0.03%
474.00		REGULATORS	0	25-SQ	0%	488,870,931	0	488,870,931	0	0.0	0.00%
475.00		MAINS - ENVISION	0	25-SQ	0%	181,264,676	0	181,264,676	0	0.0	0.00%
475.21		MAINS - COATED & WRAPPED	0	55-R3	-20%	3,320,418,328	459,630,062	3,524,871,932	0	0.0	0.00%
475.30		MAINS - PLASTIC	0	60-R4	-15%	3,480,106,028	331,594,851	3,670,527,081	2,689,281	0.0	0.08%
476.00		COMPANY NGV COMPRESSOR STATIONS	0	17-S2.5	0%	9,878,703	0	9,878,703	0	0.0	0.00%
477.00		MEASURING AND REGULATING EQUIPMENT	0	40-R2	-5%	950,956,098	32,814,539	965,689,364	219,589	0.0	0.02%
477.01		CUSTOMER M&R EQUIPMENT	0	35-R3	0%	143,726,981	0	143,726,981	0	0.0	0.00%
478.00		METERS	0	15-S2.5	0%	1,020,910,894	0	1,020,910,894	0	0.0	0.00%
TOTAL DISTRIBUTION PLANT						**14,994,747,798**	**1,329,394,913**	**15,549,492,394**	**4,257,272**		0.03%

GENERAL PLANT										
482.00	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-R1.5	0%	13,255,572	0	13,255,572	0	0.0	0.00%
482.01	STRUCTURES AND IMPROVEMENTS - VPC	2033	40-R1.5	0%	53,463,354	0	53,463,354	0	0.0	0.00%
482.04	STRUCTURES AND IMPROVEMENTS - THOROLD	2022	40-R1.5	0%	15,678,640	0	15,678,640	0	0.0	0.00%
482.05	STRUCTURES AND IMPROVEMENTS - MARKHAM	2046	40-R1.5	0%	36,671,818	0	36,671,818	0	0.0	0.00%
482.51	STRUCTURES AND IMPROVEMENTS - KEIL HEAD OFFICE	2049	40-R1.5	0%	69,558,675	0	69,558,675	0	0.0	0.00%
482.52	STRUCTURES AND IMPROVEMENTS - BLOOMFIELD TRAINING CENTER	2028	40-R1.5	0%	19,237,692	0	19,237,692	0	0.0	0.00%
483.00	OFFICE FURNITURE AND EQUIPMENT	0	15-SQ	0%	29,776,062	0	29,776,062	0	0.0	0.00%
484.00	TRANSPORTATION EQUIPMENT	0	12-L2.5	0%	134,722,078	0	134,722,078	0	0.0	0.00%
485.00	HEAVY WORK EQUIPMENT	0	17-L1.5	0%	44,128,921	0	44,128,921	0	0.0	0.00%
486.00	TOOLS AND WORK EQUIPMENT	0	15-SQ	0%	79,966,854	0	79,966,854	0	0.0	0.00%
487.70	RENTAL - REFUEL APPL	0	15-SQ	0%	864,755	0	864,755	0	0.0	0.00%
487.80	RENTAL - NGV STATIONS	0	20-SQ	0%	7,774,175	0	7,774,175	0	0.0	0.00%
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	0	10-SQ	0%	11,224,609	0	11,224,609	0	0.0	0.00%
490.00	COMPUTER EQUIPMENT	0	4-SQ	0%	30,306,679	0	30,306,679	0	0.0	0.00%
	COMPUTER EQUIPMENT - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
490.30	COMPUTER EQUIPMENT - WAMS	0	10-SQ	0%	4,680,899	0	4,680,899	0	0.0	0.00%
491.01	SOFTWARE ACQUIRED INTANGIBLES	0	4-SQ	0%	155,164,785	0	155,164,785	0	0.0	0.00%
	SOFTWARE ACQUIRED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.02	SOFTWARE DEVELOPED INTANGIBLES	0	4-SQ	0%	38,776,288	0	38,776,288	0	0.0	0.00%
	SOFTWARE DEVELOPED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.03	CIS ACQUIRED SOFTWARE	0	10-SQ	0%	87,626,214	0	87,626,214	0	0.0	0.00%
**	SOFTWARE INTANGIBLES - 10 YEAR	0	10-SQ	0%	0	0	0	0	0.0	10.00%
491.04	WAMS	0	10-SQ	0%	85,221,905	0	85,221,905	0	0.0	0.00%
TOTAL GENERAL PLANT					**918,099,975**	**0**	**918,099,975**	**0**		0.00%
TOTAL UTILITY PLANT STUDIED					**21,693,291,183**	**1,542,999,999**	**22,335,546,911**	**4,878,947**		**0.02%**
PLANT NOT STUDIED										
401.00	Franchises and Consents - Total Comp				1,175,081					
402.04	Other Intangibles - Lakeland Acquisition Adjustment				494,761					
458.00	Base Pressure and Line Pack Gas				76,135,052					
	Land (Including MacLeod Property)				177,293,391					
	Plant Held for Future Use				1,670,861					
	Inventory Adjustment				59,309,971					
***	Post Study Adjustments				5,005,525					
TOTAL PLANT NOT STUDIED					**321,084,642**					
TOTAL UTILITY PLANT IN SERVICE					**22,014,375,825**					

* Annual Accrual Rates for new major structures in Account 472.00 after 2023 are 4.02%.
** New depreciation rate for major longer term intangible asset additions post 2023
*** Adjustments between regulated and unregulated storage operations to align with updated exhibits in Enbridge Gas's 2021 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding (EB-2022-0110), as filed on September 2, 2022

ENBRIDGE GAS INC.

Answer to Undertaking from
Industrial Gas Users Association (IGUA)

Undertaking

Tr: 121

To make best efforts to show the revenue requirement impact of the last two columns referred to, with appropriate caveats.

Response:

Enbridge Gas has updated the table at Exhibit K16.2 page 4 to reflect the updated 2024 values based on the Capital Update for all the data columns. These updates are reflected in Exhibit J17.9 and the accompanying attachments.

Please see Table 1 for the revised table showing revenue requirement impacts. Please note the revenue requirement impacts do not reflect changes to rate base resulting from changes to depreciation, however these impacts are expected to be immaterial.

Table 1
Updated IGUA Chart Reflecting Capital Update

	($ millions)	Source	Cumulative Impact Revised Depreciation	Cumulative Revenue Requirement Impact
EGI Proposed 2024 Depreciation Provision	879.0	J17.9		
2024 Depreciation Provision at Current Rates	737.1	J17.9		
Proposed vs Current Provision	141.9	Calculated		
Impact of Replacing ELG with ALG	(83.4)		795.6	1,082.4
Impact of Emrydia + Intergroup Average Life Estimate Changes (Using ELG)	(233.7)	J17.9, calculated	561.9	764.5
Impact on Discounted Net Salvage @ 6.03% vs. 3.75%	(62.4)	J17.9, calculated	499.5	679.6

ENBRIDGE GAS INC.

Answer to Undertaking from
Industrial Gas Users Association (IGUA)

Undertaking

Tr: 122

To revise the table with the assumption that the Board orders the adoption of ELG.

Response:

Enbridge Gas has updated the table at K16.2 page 4 to reflect the updated 2024 values based on the Capital Update for all the data columns. These updates are reflected in Exhibit J17.9 and the accompanying attachments.

Please see Table 1 for the revised table assuming the adoption of ELG. Please note the revenue requirement impacts do not reflect changes to rate base resulting from changes to depreciation, however these impacts are expected to be immaterial.

Table 1
Updated IGUA Chart Reflecting Capital Update and Adoption of ELG

($ millions)	Depreciation	Source	Cumulative Impact Revised Depreciation	Cumulative Revenue Requirement Impact
EGI Proposed 2024 Depreciation Provision	879.0	J17.9		
2024 Depreciation Provision at Current Rates	737.1	J17.9		
Proposed vs Current Provision	141.9	Calculated		
Impact of Replacing ELG with ALG	n/a	n/a	879.0	1,195.9
Impact of Emrydia + Intergroup Average Life Estimate Changes (Using ELG)	(230.7)	J17.9, calculated	648.3	882.0
Impact on Discounted Net Salvage @ 6.03% vs. 3.75%	(72.9)	J17.9, calculated	575.4	782.9

ENBRIDGE GAS INC.

Answer to Undertaking from
Industrial Gas Users Association (IGUA)

Undertaking

Tr: 187

To confirm whether reporting requirements are similar to those established by the Alberta Utilities Commission; to opine on whether such requirements would be appropriate.

Response:

Enbridge Gas notes that this undertaking was further discussed at 17 Tr.148.

Enbridge Gas understands the question to be referring to the following recommendations from Mr. Madsen:

1. "…begin separately tracking and reporting the annual changes in the current net salvage liability. Specifically, the existing balance in the account inclusive of any approved funding to the account and actual costs incurred should be reported as a separate requirement in future rate applications."

2. " …calculate and report the expected future net salvage cost liability based on two assumptions:

i. The applied for net salvage rates.
ii. The five-year average actual experienced net salvage costs for each account."

3. "…conduct a study for its [Enbridge's] 10 largest property accounts and report on the following at the time of its [Enbridge's] future rate application:

- The current approach to salvaging the assets, including the approximate unit material and labour costs to salvage assets.
- Alternative approaches available to salvage certain assets, such as abandonment in situ, and the implications such approaches may have on salvage costs.
- Enbridge's best estimate of the future costs to salvage the assets within each account, including the assumptions used to develop those estimates."

Enbridge Gas does not have specific objections to the above recommendations. However, the Company notes that such reporting requirements would take time and require investment to implement and would ultimately be subject to data availability in the Company's systems and records. Additionally, consideration should be given to the frequency and timing of such reporting, so that a balance can be struck between operational effectiveness and cost efficiency.

The following response was provided by Concentric Energy Advisors:

In response to recommendation 1 above:
The reporting requirements for tariff applications in Alberta, as set out by the Alberta Utilities Commission (AUC), are outlined in Bulletin 2006-25 – Uniform System of Accounts and Minimum Filing Requirements (USA/MFR). The guidelines within Bulletin 2006-25 do not contain specific direction to separately track and report annual changes in the current net salvage liability. The guidelines do, however, require a utility to report on an actual and forecast basis, the life and net salvage portions of its depreciation expense provision and accumulated depreciation.

While there is no specific requirement for all utilities in Alberta to report changes in net salvage liabilities, the AUC has directed Altalink Management Ltd. (AML) in its future applications to "report by uniform system of account, both the forecast and actual costs of removal that have been recorded to the net salvage reserve account during the period of transition, capitalized or recorded in association with a terminal asset retirement."[1] The AUC imposed this future requirement as part of its approval of a change in AML's net salvage method. It is important to note that the "period of transition" in the above quote refers to a change in net salvage methodology from the traditional method of net salvage collection to expensing costs of removal in the year of occurrence. This quote should not be read as a reference to energy transition. As such, the reporting requirements for AML are not applicable to other utilities regulated by the Alberta Utilities Commission, nor any other Canadian regulator.

Concentric is unaware of any utility commission requirements elsewhere in Canada that mandate detailed net salvage liability reporting for the purposes of regulatory applications.

In response to recommendation 3 above:
Concentric is aware of a number of clients who have undergone detailed engineering-based cost of removal studies. It is our experience that these studies often take multiple

[1] Alberta Utilities Commission Decision 25870-D01-2020, Appendix 2, Direction 1.

years to complete with correspondingly large costs. As part of the National Energy Board's Land Matters Consultation Initiative, detailed engineering estimates were required to determine costs related to terminal retirements for each utility. This study process took in excess of two years and one million dollars to complete for each utility. It is the experience of Concentric that engineering-based cost of removal studies provide a more comprehensive estimate of terminal cost of removal than the method used in the Concentric depreciation study, however, these detailed estimates often result in a significant increase in future costs of removal requirements. Furthermore, when these studies are conducted on large diameter pipelines through rural environments, it is often expected that there may be a significant variance from the forecasted cost of retirement amounts to the actual costs at the time of removal due to the impacts of inflation and changing environmental legislation. Concentric anticipates that this variance may be even larger in the circumstances of Enbridge Gas due to the high-density urban environment where distribution assets are most common.

Concentric is unaware of any natural gas distribution utilities in Canada that have undergone this study process largely because these studies are more accurate at detailing costs related to terminal retirements. As such, these studies are most often conducted on electric generation facilities, natural gas storage assets, and large inter-provincial pipelines due to the ability to predict the terminal retirement date in order to forward inflate the current dollar costs of retirement.

Due to the above, if the OEB rules such a study necessary for Enbridge Gas, Concentric would recommend that the OEB provide a detailed framework for the parameters and expectations of the work required for the study. Furthermore, Concentric would recommend the study be filed as part of the next general rate case to provide ample time for thorough completion.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 28

To file an updated Attachment 3 to Exhibit 4, Tab 5, Schedule 1.

Response:

Please see Attachment 1.

2024 Test Year Depreciation Expense - EGI

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Intangible Plant			
1	Franchises and consents	1.2		0.0
2	Intangible plant - Other	0.5		0.0
3	Total	1.7		0.0
	Local Storage Plant			
4	Structures and improvements	7.3	1.69%	0.1
5	Gas holders - storage	7.3	0.96%	0.1
6	Gas holders - equipment	23.1	1.06%	0.2
7	Total	37.7		0.4
	Underground Storage Plant			
8	Land rights	74.8	1.48%	1.1
9	Structures and improvements	111.6	2.84%	3.2
10	Wells	152.8	3.85%	5.8
11	Wells Equipment	16.4	1.32%	0.2
12	Field Lines	394.1	2.54%	9.9
13	Compressor equipment	742.5	2.88%	21.4
14	Measuring & regulating equipment	211.2	2.60%	5.4
15	Total	1,703.5		46.9
	Transmission Plant			
16	Land rights	92.4	1.71%	1.6
17	Compressor Structures and improvements	166.5	2.07%	3.4
18	Measuring and Regulating Structures and Improvements	11.4	1.40%	0.2
19	Equipment	3.3	5.48%	0.2
20	Mains	2,976.4	1.77%	52.4
21	Compressor equipment	1,039.8	3.72%	38.7
22	Measuring & regulating equipment	504.6	3.06%	15.2
23	Total	4,794.4		111.7

2024 Test Year Depreciation Expense - EGI (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Distribution Plant			
24	Renewable Natural Gas (2)	31.9	Various	1.0
25	Land rights	68.1	1.80%	1.2
26	Structures and improvements - Other	215.1	3.17%	5.9
27	Structures and improvements - Stoney Creek	33.9	4.47%	1.5
28	Structures and improvements - Win-Rhodes	26.3	4.27%	1.1
29	Structures and improvements - London Admin	22.5	11.95%	2.7
30	Structures and improvements - Kingston Office	19.0	4.21%	0.8
31	Structures and improvements - Mainway	18.1	14.21%	2.6
32	Services - metallic	680.4	4.43%	30.0
33	Services - plastic	5,056.3	2.73%	136.7
34	Regulators	530.1	8.86%	46.3
35	Mains - Envision	181.3	5.78%	10.5
36	Mains - coated and wraped	3,857.4	3.38%	129.7
37	Mains - plastic	3,969.7	2.72%	107.0
38	Company NGV Compressor Stations	13.3	3.70%	0.5
39	Measuring & regulating equipment	1,043.2	2.89%	30.9
40	Customer M&R Equipment	169.9	3.34%	5.6
41	Meters	1,179.3	10.25%	119.9
42	Total	17,115.6		633.8
	General			
43	Investment in leased assets	16.3		0.6
44	Structures and improvements - Other	21.7	1.44%	0.3
45	Structures and improvements - VPC	90.9	6.36%	5.8
46	Structures and improvements - Thorold	0.0	59.23%	0.0
47	Structures and improvements - Markham	37.1	4.21%	1.6
48	Structures and improvements - Keil	88.1	5.62%	4.9
49	Structures and improvements - Bloomfield	21.6	14.63%	3.2
50	Office furniture and equipment	42.8	4.03%	1.7
51	Transporation equipment	146.1	4.65%	6.7
52	Heavy work equipment	52.4	8.29%	4.3
53	Tools and other equipment	86.6	11.92%	10.3
54	Rental - Refuel Appl	2.5	10.05%	0.3
55	Rental - NGV Stations	5.3	3.71%	0.4
56	Communications structures and equipment	8.3	26.25%	2.1
57	Computer Equipment	26.0	13.34%	4.0
58	Computer Equipment - post 2023	10.9	25.00%	2.0

2024 Test Year Depreciation Expense - EGI (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
59	Software Acquired Intangibles	103.2	8.77%	10.6
60	Software Acquired Intangibles - post 2023	12.0	25.00%	2.2
61	Software Developed Intangibles	32.5	10.04%	3.7
62	Software Developed Intangibles - post 2023	13.4	25.00%	2.5
63	CIS Acquired Software	120.5	8.24%	9.9
64	TIS/IT Software	0.0	10.00%	0.0
65	WAMS	85.2	10.74%	9.2
66	Total	1,023.5		86.1
67	Plant held for future use	1.7	3.63% 2.73%	0.0
68	Total	24,678.1	3.56%	879.0

Notes:
(1) Average of the opening and closing plant balances.
(2) Represents forecasted RNG projects in total using a blended rate of assets.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 31

To provide a calculation of percentage growth and revenue attributable to customer growth, and applied to base depreciation and escalated.

Response:

Please see Attachment 1 which provides the notional depreciation included in base rates for the EGD and Union rate zones, as well as the combined total, for the years 2013 through 2023.

For the EGD rate zone, the depreciation amounts approved and included in 2013 through 2018 rates were determined in EGD's 2013 Cost of Service and 2014 through 2018 custom incentive regulation proceedings, and as such were not subject to PCI or growth escalation. EGD rate zone notional depreciation amounts for 2019 through 2023 have been calculated by applying PCI and growth escalation to the approved 2018 depreciation amount.

For the Union rate zones, the 2013 OEB approved depreciation amount was determined in Union's 2013 Cost of Service proceeding, and notional depreciation amounts for 2014 through 2023 have been determined by applying PCI and growth escalation to the approved 2013 depreciation amount.

Enbridge Gas notes that these calculated notional depreciation amounts included in base rates do not include depreciation recovered in the EGD rate zone through the ICM mechanism, or amounts recovered through the capital pass through and ICM mechanisms in the Union rate zones.

As was noted in the oral hearing, while the Company understands the intent of the provided calculations, it does not believe that under a price cap rate setting mechanism it is necessarily appropriate or meaningful to escalate individual base year cost elements, as the Company is intended to manage all of its costs under its escalated

rates, with the understanding that each individual base year cost element will likely increase or decrease at a rate that differs from the price cap escalation and growth. Additionally, changes in depreciation could vary from year to year, or as compared to forecasts, depending on the mix of assets placed into service and the depreciation rates associated with those asset classes.

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
EGD Rate Zone	EB-2011-00354	EB-2012-0459	EB-2012-0459/ EB-2014-0276	EB-2012-0459/ EB-2015-0114	EB-2012-0459/ EB-2016-0215	EB-2012-0459/ EB-2017-0086	EB-2018-0305	EB-2019-0194	EB-2020-0095	EB-2021-0147	EB-2022-0133
General Service (1)						2,184,345	2,210,319	2,233,618	2,257,238	2,282,422	2,307,139
Contract Market (2)						414	405	454	517	505	536
						2,184,759	2,210,724	2,234,072	2,257,755	2,282,927	2,307,675
Growth EGD							1.19%	1.06%	1.06%	1.11%	1.08%
PCI							1.07%	1.31%	1.70%	1.40%	3.60%
Depreciation or Notional Depreciation In Base Rates	279	249	262	289	298	306	312	320	329	337	353

Union Rate Zones	EB-2011-0210	EB-2013-0365	EB-2014-0271	EB-2015-0116	EB-2016-0245	EB-2017-0087	EB-2018-0305	EB-2019-0194	EB-2020-0095	EB-2021-0147	EB-2022-0133
General Service (1)	1,386,925	1,406,715	1,426,394	1,446,314	1,465,747	1,486,294	1,504,849	1,522,654	1,538,182	1,552,739	1,567,149
Contract Market (2)	484	476	468	465	476	477	500	515	519	535	494
	1,387,409	1,407,191	1,426,862	1,446,779	1,466,223	1,486,771	1,505,349	1,523,169	1,538,701	1,553,274	1,567,643
Growth Union		1.43%	1.40%	1.40%	1.34%	1.40%	1.25%	1.18%	1.02%	0.95%	0.93%
PCI		0.51%	0.82%	0.80%	0.66%	0.51%	1.07%	1.31%	1.70%	1.40%	3.60%
Depreciation or Notional Depreciation In Base Rates	196	200	204	209	213	217	222	228	234	239	250
Total Depreciation or Notional Depreciation In Base Rates	**475**	**448**	**466**	**498**	**511**	**523**	**535**	**547**	**562**	**576**	**603**

1 Exhibit 3, Tab 2, Schedule 6, Attachment 2, page 1
2 Exhibit 3, Tab 2, Schedule 8, attachment 2, page 1-3

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 36

To advise on tax impacts on closing existing accounts and setting up new accounts for fast-depreciation new assets.

Response:

Enbridge Gas's tax team reviews changes to the plant account structure during the forecast process to ensure that assets are correctly reflected in the appropriate capital cost allowance (CCA) classes. In the instance of the new hardware and software accounts there is no impact from a tax perspective and the CCA classes remain unchanged from the existing hardware and software accounts.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 45

Using Mr. Shepherd's spreadsheet, to add 1,000 for each side for all years, each year, and inflate those using any inflation rate, over a 40-year period.

Response:

The following response was provided by Concentric Energy Advisors:

Please refer to Attachment 1. In providing the attachment, Concentric did not have access to Mr. Shepherd's spreadsheet. In order to complete this undertaking response Concentric developed a spreadsheet in accordance with the request from SEC. The spreadsheet assumes the following:

- A $1,000 expenditure with a 5-year life estimate and a second $1,000 expenditure with a 15-year life in year 1.
- An additional expenditure is made in years 2 through 40 in the same amounts adjusted with a 2% annual inflation factor. These annual expenditures are assumed to have the same life expectancies as the expenditures in year 1 (a 5-year and a 15-year asset life).
- An annual retirement amount begins at age 5 for the year 1 asset and repeats every year to retire the 5-year assets installed in each of the years 2 through 40.
- A second annual retirement amount begins at age 15 for the year 1 asset and repeats every year to retire the 15-year assets installed in each of the years 2 through 40.
- Additions cease in year 40 as requested in the undertaking.
- Retirements continue through age 54 to retire the asset additions through age 40 recognizing the 5- and 15-year life estimates for the age 40 asset additions.
- Additions are assumed to occur at the beginning of each year and retirements are assumed to occur at year end.

At Tr. Vol. 17, page 41, lines 18-27, Mr. Shepherd and Mr. Kennedy had the following exchange:

> Mr. Shepherd: “And so I just made it more complicated. And what it appears to me, and tell whether this is right, is that, if you do what it looks like in the real world, add assets every year and retire them on a normal pattern, and inflate the assets, you would get to the point where ELG is about 30 percent higher than ALG every single year”
>
> Mr. Kennedy:” Sir, it’s our –and we ran ELG versus ALG calculations consistently. Your 30 percent is quite overstated. In reality, it is more like 10 percent.”

As noted in the Attachment 1, in contrast to Mr. Shepherd’s assumption of ELG being “30 percent higher than ALG every single year”, the annual increase in the use of the ELG procedure only exists at approximately 30 percent in the first 5-year period before the impact of the retirement of the fully depreciated 5-year asset is realized. Over the entire 40-year period of additions, the amount of the ELG increase reduces to 10 percent or less by year 11, and averages around 2 percent from years 15 through 40. In fact, the average amount of increase in the use of the ELG procedure for the period from year 1 to year 40 is an increase of 8.9 percent, which aligns to the testimony of Mr. Kennedy of a 10% increase.

For the 15-year period after age 40, the ELG expense reduces from 98 percent (as compared to the ALG expense) to 67 percent for the last 10-years of the account's life. Consistent with the example, the actual life experience of Mr. Kennedy is that once utilities enter a period of increased retirement experience, the impact of the ELG procedure significantly declines as compared to the ALG procedure.

ENBRIDGE GAS INC.
Illustrative Example of a ELG versus ALG Calacuation in a Growing and On-going Account

Average Life Group

Year	Depreciation Expense	Additions	Retirements	Asset Account Balance	Accumulated Depreciation Balances	NBV
1	200	2000		2,000	200	1,800
2	404	2,040		4,040	604	3,436
3	612	2,081		6,121	1,216	4,905
4	824	2,122		8,243	2,040	6,203
5	1,041	2,165	1,000	9,408	2,081	7,327
6	1,162	2,208	1,020	10,596	2,223	8,373
7	1,285	2,252	1,040	11,808	2,467	9,341
8	1,411	2,297	1,061	13,044	2,817	10,228
9	1,539	2,343	1,082	14,305	3,273	11,032
10	**1,670**	**2,390**	**1,104**	**15,591**	**3,838**	**11,753**
11	1,803	2,438	1,126	16,903	4,515	12,388
12	1,939	2,487	1,149	18,241	5,306	12,936
13	2,078	2,536	1,172	19,606	6,212	13,394
14	2,219	2,587	1,195	20,998	7,236	13,762
15	**2,364**	**2,639**	**2,219**	**21,418**	**7,381**	**14,038**
16	2,411	2,692	2,263	21,846	7,528	14,318
17	2,459	2,746	2,309	22,283	7,679	14,605
18	2,508	2,800	2,355	22,729	7,832	14,897
19	2,559	2,856	2,402	23,184	7,989	15,195
20	**2,610**	**2,914**	**2,450**	**23,647**	**8,149**	**15,499**
21	2,662	2,972	2,499	24,120	8,312	15,809
22	2,715	3,031	2,549	24,603	8,478	16,125
23	2,769	3,092	2,600	25,095	8,648	16,447
24	2,825	3,154	2,652	25,597	8,820	16,776
25	**2,881**	**3,217**	**2,705**	**26,109**	**8,997**	**17,112**
26	2,939	3,281	2,759	26,631	9,177	17,454
27	2,998	3,347	2,814	27,163	9,360	17,803
28	3,058	3,414	2,871	27,707	9,548	18,159
29	3,119	3,482	2,928	28,261	9,738	18,522
30	**3,181**	**3,552**	**2,986**	**28,826**	**9,933**	**18,893**
31	3,245	3,623	3,046	29,402	10,132	19,271
32	3,310	3,695	3,107	29,991	10,335	19,656
33	3,376	3,769	3,169	30,590	10,541	20,049
34	3,443	3,844	3,233	31,202	10,752	20,450
35	**3,512**	**3,921**	**3,297**	**31,826**	**10,967**	**20,859**
36	3,583	4,000	3,363	32,463	11,186	21,276
37	3,654	4,080	3,431	33,112	11,410	21,702
38	3,727	4,161	3,499	33,774	11,638	22,136
39	3,802	4,245	3,569	34,450	11,871	22,579
40	**3,878**	**4,329**	**3,640**	**35,139**	**12,109**	**23,030**
41	3,514		3,713	31,425	11,909	19,516
42	3,143		3,788	27,638	11,264	16,374
43	2,764		3,863	23,774	10,165	13,610
44	2,377		3,941	19,834	8,601	11,232
45	**1,983**		**1,811**	**18,023**	**8,773**	**9,249**
46	1,802		1,848	16,175	8,728	7,447
47	1,617		1,885	14,290	8,461	5,829
48	1,429		1,922	12,368	7,968	4,400
49	1,237		1,961	10,408	7,244	3,163
50	**1,041**		**2,000**	**8,408**	**6,285**	**2,123**
51	841		2,040	6,368	5,086	1,282
52	637		2,081	4,287	3,642	645
53	429		2,122	2,165	1,948	216
54	216		2,165	-	-	-
55	**-**		**-**	**-**	**-**	**-**
	120,804	120,804	120,804			

Assumes:

(1) Assumes annual capital additions of $2,000 (Inflation adjusted) of two assets - one with a 5 year life and a second with a 15 year life
(2) 10% depreciation rate (5+15)/2

(3) Additions are added at beginning of year and retirement are removed at end of year
(4) Assumes an annual inflation amount of 2%

Equal Life Group

Year	Depreciation Expense	Additions	Retirements	Asset Account Balance	Accumulated Depreciation Balances	NBV	Variance in NBV	ELG/ALG	
1	267	2,000		2,000	267	1,733	- 67	1.333333	
2	539	2,040		4,040	806	3,234	- 202	1.333333	
3	816	2,081		6,121	1,622	4,499	- 406	1.333333	
4	1,099	2,122		8,243	2,721	5,522	- 680	1.333333	
5	1,388	2,165	1,000	9,408	3,109	6,299	- 1,027	1.333333	
6	1,415	2,208	1,020	10,596	3,504	7,092	- 1,281	1.218265	
7	1,578	2,252	1,040	11,808	4,042	7,766	- 1,575	1.228523	
8	1,743	2,297	1,061	13,044	4,724	8,320	- 1,907	1.235953	
9	1,777	2,343	1,082	14,305	5,419	8,887	- 2,146	1.154766	
10	**1,879**	**2,390**	**1,104**	**15,591**	**6,194**	**9,398**	**- 2,355**	**1.12553**	
11	1,983	2,438	1,126	16,903	7,051	9,852	- 2,536	1.100079	
12	2,090	2,487	1,149	18,241	7,992	10,249	- 2,686	1.077727	
13	2,198	2,536	1,172	19,606	9,018	10,588	- 2,807	1.057943	
14	2,309	2,587	1,195	20,998	10,132	10,866	- 2,896	1.040312	
15	**2,422**	**2,639**	**2,219**	**21,418**	**10,335**	**11,084**	**- 2,954**	**1.024505**	
16	2,470	2,692	2,263	21,846	10,541	11,305	- 3,013	1.024505	
17	2,519	2,746	2,309	22,283	10,752	11,531	- 3,073	1.024505	
18	2,570	2,800	2,355	22,729	10,967	11,762	- 3,135	1.024505	
19	2,621	2,856	2,402	23,184	11,187	11,997	- 3,198	1.024505	
20	**2,674**	**2,914**	**2,450**	**23,647**	**11,410**	**12,237**	**- 3,261**	**1.024505**	
21	2,727	2,972	2,499	24,120	11,638	12,482	- 3,327	1.024505	
22	2,782	3,031	2,549	24,603	11,871	12,731	- 3,393	1.024505	
23	2,837	3,092	2,600	25,095	12,109	12,986	- 3,461	1.024505	
24	2,894	3,154	2,652	25,597	12,351	13,246	- 3,530	1.024505	
25	**2,952**	**3,217**	**2,705**	**26,109**	**12,598**	**13,511**	**- 3,601**	**1.024505**	
26	3,011	3,281	2,759	26,631	12,850	13,781	- 3,673	1.024505	
27	3,071	3,347	2,814	27,163	13,107	14,057	- 3,746	1.024505	
28	3,133	3,414	2,871	27,707	13,369	14,338	- 3,821	1.024505	
29	3,195	3,482	2,928	28,261	13,636	14,624	- 3,898	1.024505	
30	**3,259**	**3,552**	**2,986**	**28,826**	**13,909**	**14,917**	**- 3,976**	**1.024505**	
31	3,324	3,623	3,046	29,402	14,187	15,215	- 4,055	1.024505	
32	3,391	3,695	3,107	29,991	14,471	15,520	- 4,136	1.024505	
33	3,459	3,769	3,169	30,590	14,760	15,830	- 4,219	1.024505	
34	3,528	3,844	3,233	31,202	15,056	16,147	- 4,303	1.024505	
35	**3,598**	**3,921**	**3,297**	**31,826**	**15,357**	**16,470**	**- 4,390**	**1.024505**	
36	3,670	4,000	3,363	32,463	15,664	16,799	- 4,477	1.024505	
37	3,744	4,080	3,431	33,112	15,977	17,135	- 4,567	1.024505	
38	3,819	4,161	3,499	33,774	16,297	17,478	- 4,658	1.024505	
39	3,895	4,245	3,569	34,450	16,623	17,827	- 4,751	1.024505	
40	**3,973**	**4,329**	**3,640**	**35,139**	**16,955**	**18,184**	**- 4,846**	**1.024505**	**1.088572**
41	3,464		3,713	31,425	16,705	14,720	- 4,796	0.985693	
42	2,944		3,788	27,638	15,862	11,776	- 4,598	0.93684	
43	2,414		3,863	23,774	14,413	9,362	- 4,248	0.873487	
44	1,874		3,941	19,834	12,346	7,488	- 3,744	0.788071	
45	**1,322**		**1,811**	**18,023**	**11,856**	**6,166**	**- 3,083**	**0.666667**	
46	1,202		1,848	16,175	11,210	4,965	- 2,482	0.666667	
47	1,078		1,885	14,290	10,404	3,886	- 1,943	0.666667	
48	953		1,922	12,368	9,435	2,934	- 1,467	0.666667	
49	825		1,961	10,408	8,299	2,109	- 1,054	0.666667	
50	**694**		**2,000**	**8,408**	**6,992**	**1,415**	**- 708**	**0.666667**	
51	561		2,040	6,368	5,513	855	- 427	0.666667	
52	425		2,081	4,287	3,857	430	- 215	0.666667	
53	286		2,122	2,165	2,020	144	- 72	0.666667	
54	144		2,165	-	-	-	-	0.666667	0.683384
			-	**-**	**-**	**-**			
			-	-					
	120,804	120,804	120,804						

Assumes:

(1) Assumes annual capital additions of $2,000 (Inflation adjusted) of two assets - one with a 5 year life and a second with a 15 year life
(2)Depreciation rate = (50% of the sum of last 15 years/15)+((50% of the sum of last 5 years/5)

(3) Additions are added at beginning of year and retirement are removed at end of year
(4) Assumes an annual inflation amount of 2%

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 51

To provide the current CARFR rate.

Response:

The current 2024 CARF rate is 4.48% This is based on the 30-year bank forecast Government of Canada bond rate of 3.00% from a July 25, 2023, forecast plus the credit spread of 1.48%. The forecasted amount of net salvage collected at the rate of 4.48% is $55 million based on the 2024 Capital Update. The Government of Canada 30-year bond yield has increased since the application was prepared and filed in 2022.

As presented in Exhibit I.1.8-STAFF-17, Enbridge Gas's annual site restoration costs were projected to be approximately $60 million annually during the IRM term at the time of filing the application. These costs have been on the rise and could fluctuate significantly depending on the assets being retired. For example, in 2022, Enbridge Gas' site restoration costs net of proceeds was $64.1 million and are forecasted to be $97.1 million in 2023[1].

It should be noted that the use of the 4.48% discount rate would not only under recover relative to forecast annual site restoration costs, but it would also not recover any funds to add to the accrual balance for future SRC's.

Enbridge Gas prepared Table 1 to present the net salvage accrual within the depreciation provision at various discount rates. A discount rate higher than 3.75%, such as 4.48%, would result in net salvage amounts collected being lower than historical and forecasted site restoration costs of at least $60 million per year.

[1] Exhibit 2, Tab 2, Schedule 1, page 4, Table 2, line 5. .

Table 1
Impacts from Changes in CDNS Discount Rate

($ millions)	2024 Net Salvage Accrual within Depreciation Provision	2024 Depreciation Provision	2024 Revenue Requirement
4.48%	55.0	839.7	1,142.4
3.75% - EGI proposal	96.3	879.0	1,195.9
3.25%	133.6	915.5	1,245.6
3.095%	146.5	928.0	1,262.6

Notes:
(1) 3.75% is EGI's proposal revised based on the Capital Update in Exhibit 2, Tab 4, Schedule 5
(2) 4.48% is the current CARF rate at July 25, 2023
(3) 3.095% is EGD's current discount rate per EB-2012-0459
(4) 3.25% is the rate applied by CER-regulated abandonment trusts in Exhibit K16.2, page 5 combining the rate of return and inflation rate

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Greenhouse Vegetable Growers (OGVG)

Undertaking

Tr: 57

To review the table at K16.2, page 4, to provide line-by-line impacts making up the 572.6 number and 509.0 number.

Response:

Enbridge Gas interprets this question to be in reference to updating page 4 of the table at K16.2 to reflect the updated 2024 values based on the Capital Update for all the data columns.

Please see Attachment 1, which presents variances as requested. For the underlying values driving the variances, please see Exhibit J17.9, Attachment 3.

ENBRIDGE GAS INC. DEPRECIATION PROVISION COMPARISON

		EGI PROPOSAL	Variances			
Asset Account (a)	Concentric Recommended Life and Curve (1) (b)	EQUAL LIFE GROUP CDNS 3.75% (2) (c)	AVERAGE LIFE GROUP CDNS 3.75% (2) (d)	Intervenor Recommended Life and Curve (e)	ALG + Intervenor Life and Curve CDNS 3.75% (2) (f)	ALG + Intervenor Life and Curve CDNS 6.03% (2) (g)
442.00	40-S5	121,037	(2,182)	N/A	0	0
443.01	45-R4	70,295	(4,926)	N/A	0	0
443.02	55-R4	245,157	(16,292)	N/A	0	0
451.00	55-R4	1,103,268	(32,688)	N/A	0	0
452.00	45-R3	3,164,111	(593,650)	45-R2.5	(127,649)	(326,461)
453.00	45-R2.5	5,806,931	(1,028,103)	N/A	0	(905,732)
454.00	40-R2	215,265	(50,348)	N/A	0	0
455.00	55-R3	9,857,986	(1,214,054)	N/A	0	(473,957)
456.00	40-R4	21,390,221	(1,731,415)	44-R4	(3,022,416)	(3,917,989)
457.00	35-R3	5,389,636	(675,213)	40-R2.5	(1,212,631)	(1,702,678)
461.00	60-R4	1,558,436	(101,347)	N/A	0	0
462.00	50-S4	3,442,222	(103,452)	N/A	0	(145,767)
463.00	55-S4	160,119	(9,380)	N/A	0	(8,971)
464.00	30-L0.5	180,907	(64,838)	N/A	0	(1,433)
465.00	60-R4	52,439,913	(3,682,569)	70-R4	(9,926,499)	(13,296,088)
466.00	30-R4	38,709,127	(3,120,140)	37-R4	(9,843,911)	(10,667,066)
467.00	40-R4	15,204,608	(1,085,084)	N/A	0	(1,206,053)
471.00	60-R4	1,221,703	(83,595)	N/A	0	0
472.00	40-S0.5	5,945,106	(586,377)	N/A	0	0
472.31	40-S0.5	1,516,289	(166,054)	N/A	0	0
472.32	40-S0.5	1,125,018	(120,854)	N/A	0	0
472.33	40-S0.5	2,684,144	(13,878)	N/A	0	0
472.34	40-S0.5	798,633	(86,081)	N/A	0	0
472.35	40-S0.5	2,569,080	(18,912)	40-S0.5 - No Truncation	(2,080,240)	(2,080,240)
473.01	40-S0.5	29,969,149	(7,392,542)	50-L1	(8,927,720)	(11,801,418)
473.02	55-S3	136,735,162	(12,730,194)	60-S3	(17,505,276)	(34,755,879)
474.00	25-SQ	46,298,774	0	50-L1	(35,427,798)	(35,427,798)
475.00	25-SQ	10,469,399	0	N/A	0	0
475.21	55-R3	129,657,949	(16,535,917)	70-R3	(42,961,677)	(59,843,485)
475.30	60-R4	107,007,350	(7,604,579)	70-R2	(27,581,374)	(43,269,974)
476.00	17-S2.5	482,255	(53,035)	N/A	0	0
477.00	40-R2	30,924,387	(5,969,326)	N/A	0	(1,170,031)
477.01	35-R3	5,584,218	(727,173)	N/A	0	0
478.00	15-S2.5	119,877,761	(15,192,152)	25-L1.5	(71,731,940)	(71,731,940)
482.00	40-R1.5	302,463	(90,630)	N/A	0	0
482.01	40-R1.5	5,780,346	(187,366)	N/A	0	0
482.04	40-R1.5	0	0	N/A	0	0
482.05	40-R1.5	1,562,381	(158,339)	N/A	0	0
482.51	40-R1.5	4,945,676	(686,739)	N/A	0	0
482.52	40-R1.5	3,164,180	(34,778)	N/A	0	0
483.00	15-SQ	1,732,767	156,462	N/A	0	0
484.00	12-L2.5	6,708,608	(1,267,922)	N/A	0	0
485.00	17-L1.5	4,305,666	(1,017,314)	N/A	0	0
486.00	15-SQ	10,258,875	0	N/A	0	0
487.70	15-SQ	250,902	0	N/A	0	0
487.80	20-SQ	352,999	4,020	N/A	0	0
488.00	10-SQ	2,088,746	0	N/A	0	0
490.00	4-SQ	3,990,450	226,928	N/A	0	0
490.00 (Post 2023)	4-SQ	1,958,107	0	N/A	0	0
490.30	10-SQ	0	0	N/A	0	0
491.01	4-SQ	10,638,821	171,922	5-SQ	(2,445,274)	(2,445,274)
491.01 (Post 2023)	4-SQ	2,158,742	0	5-SQ	0	0
491.02	4-SQ	3,730,251	93,993	5-SQ	(893,032)	(893,032)
491.02 (Post 2023)	4-SQ	2,520,837	0	5-SQ	0	0
491.03	10-SQ	9,922,379	189,243	N/A	0	0
Software Intangibles - 10YR	10-SQ	0	0	N/A	0	0
491.04	10-SQ	9,153,052	0	N/A	0	0
RNG and Sales-type lease assets		1,532,536	0		0	0
TOTAL OF COLUMN CHANGES			**(83,396,868)**		**(233,687,437)**	**(296,071,265)**
			Variance vs column (c)		Variance vs column (d)	Variance vs column (d)
AGGREGATE OF PROPOSED CHANGES			**(83,396,868)**		**(317,084,305)**	**(379,468,133)**
			Variance vs column (c)		Variance vs column (c)	Variance vs column (c)

2024 DEPRECIATION @ EGI OR INTERVENOR PROPOSED DEPRECIATION RATES	**878,984,399**	**795,587,531**		**561,900,094**	**499,516,266**

2024 DEPRECIATION @ CURRENT DEPRECIATION RATES (3)	**737,115,889**

NOTES

(1) Consistent with Capital Update at Exhibit 2, Tab 5, Schedule 4, Attachment 1

(2) See Exhibit J17.1 for details

(3) See Exhibit J16.5 for details

ENBRIDGE GAS INC.

Answer to Undertaking from
Three Fires Group Inc. (Three Fires)

Undertaking

Tr: 64

To file federal government's draft clean energy for electricity regulations.

Response:

Please see Attachment 1 for the unofficial version of the Clean Electricity Regulations, released August 10, 2023, and subject to a 75-day public consultation process. Final regulations are expected to be published in Canada Gazette, Part II, in 2024.

Règlement sur l'électricité propre
Version Non Officielle

Clean Electricity Regulations
Unofficial Version

Clean Electricity Regulations

Purpose

Purpose

1 These Regulations establish a regime for limiting carbon dioxide (CO_2) emissions that result from the generation of electricity from the combustion of fossil fuels.

Interpretation

Interpretation

2 (1) The following definitions apply in these Regulations.

API means the American Petroleum Institute. (*API*)

ASTM means ASTM International, formerly known as the American Society for Testing and Materials. (*ASTM*)

auditor means an individual who

(a) is independent of the responsible person that is to be audited; and

(b) has knowledge of and has experience with respect to

(i) the certification, operation and relative accuracy test audit of continuous emission monitoring systems, and

(ii) quality assurance and quality control procedures in relation to those systems. (*vérificateur*)

authorized official means

(a) in respect of a responsible person that is a corporation, an officer of the corporation that is authorized to act on its behalf;

(b) in respect of a responsible person that is an individual, that individual or an individual who is authorized to act on that individual's behalf; and

(c) in respect of a responsible person that is another entity, an individual authorized to act on that other entity's behalf. (*agent autorisé*)

Règlement sur l'électricité propre

Objet

Objet

1 Le présent règlement établit un régime visant la réduction des émissions de dioxyde de carbone (CO_2) provenant de la production d'électricité à partir de la combustion de combustibles fossiles.

Définitions et interprétation

Définitions

2 (1) Les définitions qui suivent s'appliquent au présent règlement.

agent autorisé

a) Dans le cas où la personne responsable est une personne morale, celui de ses dirigeants qui est autorisé à agir en son nom;

b) dans le cas où elle est une personne physique, celle-ci ou la personne physique qui est autorisée à agir en son nom;

c) dans le cas où elle est une autre entité, la personne physique qui est autorisée à agir en son nom. (*authorized official*)

API L'American Petroleum Institute. (*API*)

ASTM L'ASTM International, auparavant connue sous le nom de American Society for Testing and Materials. (*ASTM*)

biomasse Vise les plantes ou matières végétales, déchets d'origine animale ou leurs produits dérivés, notamment le bois et les produits du bois, le charbon de bois, les résidus d'origine agricole, la matière organique d'origine biologique dans les déchets urbains et industriels, les gaz d'enfouissement, les bioalcools, la liqueur de cuisson, les gaz de digestion des boues ainsi que les combustibles d'origine animale ou végétale. (*biomass*)

capacité de production d'électricité À l'égard d'un groupe et d'une année civile :

a) soit la puissance maximale — la puissance nette maximale qui peut être maintenue en continu par le groupe, dans des conditions normales — la plus

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biomass means plants or plant materials, animal waste or any product made of either of these, including wood and wood products, bio-charcoal, agricultural residues, biologically derived organic matter in municipal and industrial wastes, landfill gas, bio-alcohols, pulping liquor, sludge digestion gas and fuel from animal or plant origin. (*biomasse*)

coal includes petroleum coke and synthetic gas that is derived from coal or petroleum coke. (*charbon*)

coal gasification system includes a coal gasification system that is in part located underground. (*système de gazéification du charbon*)

combustion engine means an engine, other than an engine that is self-propelled or designed to be propelled while performing its function, that

(a) operates according to the Brayton thermodynamic cycle and combusts fossil fuel to produce a net amount of motive power; or

(b) combusts fossil fuel and uses reciprocating motion to convert thermal energy into mechanical work. (*moteur à combustion*)

commissioning date means the day on which the oldest boiler or combustion engine in the unit starts operating. (*date de mise en service*)

continuous emission monitoring system or ***CEMS*** means equipment for the sampling, conditioning and analyzing of emissions from a given source and the recording of data related to those emissions. (*système de mesure et d'enregistrement en continu des émissions* ou *SMECE*)

electricity generation capacity, in relation to a unit and a calendar year, means

(a) the maximum continuous rating — the maximum net power than can be continuously sustained by the unit at standard conditions — of the unit, expressed in MW, as most recently reported to a provincial authority of competent jurisdiction or to the electric system operator in the province where the unit is located; or

(b) if no report has been made, the most electricity that was produced for sale by the unit, expressed in MW, during two continuous hours in that calendar year. (*capacité de production d'éléctricité*)

facility means units, buildings, other structures, stationary equipment — including equipment used for hydrogen fuel production and equipment used for fuel production

récente qui a été déclarée à l'autorité provinciale responsable ou à l'exploitant de réseau électrique dans la province où le groupe se trouve, exprimée en MW;

b) soit, en l'absence d'une telle déclaration, la quantité maximale d'électricité destinée à la vente qui est produite de façon continue par ce groupe pendant deux heures au cours de l'année en cause, exprimée en MW. (*electricity generation capacity*)

charbon Sont assimilés au charbon le coke de pétrole et le gaz de synthèse provenant du charbon ou du coke de pétrole. (*coal*)

combustible fossile Combustible autre que la biomasse. Y est assimilé l'hydrogène. (*fossil fuel*)

conditions normales Conditions qui correspondent à une température de 15 °C et à une pression de 101,325 kPa. (*standard conditions*)

date de mise en service Date à laquelle la plus vieille chaudière ou le plus vieux moteur à combustion du groupe commence à fonctionner. (*commissioning date*)

énergie thermique utile Énergie, sous forme de vapeur ou d'eau chaude, destinée à être utilisée à une fin, autre que la production d'électricité, qui, n'était l'utilisation de cette vapeur ou de cette eau chaude, nécessiterait la consommation d'énergie sous forme de combustible ou d'électricité. (*useful thermal energy*)

exploitant Personne ayant toute autorité sur un groupe. (*operator*)

groupe Ensemble qui est constitué de tout équipement physiquement raccordé et fonctionnant ensemble pour produire de l'électricité et qui répond aux conditions suivantes :

a) il comporte au moins une chaudière ou un moteur à combustion;

b) il peut comporter des brûleurs d'appoint et d'autres dispositifs de combustion, des systèmes de récupération de chaleur, des turbines à vapeur, des générateurs, des dispositifs de contrôle des émissions et des systèmes de captage et de stockage de carbone. (*unit*)

installation Ensemble des groupes, bâtiments, autres structures et équipements fixes — y compris les équipements utilisés pour la production d'hydrogène et ceux utilisés pour la production de carburant à partir de la gazéification du charbon — sur un site unique, ou sur des sites contigus ou adjacents qui fonctionnent comme un

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from coal gasification — on a single site or on contiguous sites or adjacent sites that function as a single integrated site at which an industrial activity is carried out. (*installation*)

fossil fuel means a fuel other than biomass. It includes hydrogen gas. (*combustible fossile*)

GHGRP means the document entitled *Canada's Greenhouse Gas Quantification Requirements, Greenhouse Gas Reporting Program*, published by the Department of the Environment in 2021. (*méthode d'ECCC*)

NERC means the North American Electric Reliability Corporation. (*NERC*)

net exports means for a given calendar year, the amount of electricity exported from a unit to an electricity system that is subject to NERC standards minus the amount of electricity imported to a unit from an electricity system that is subject to NERC standards, in GWh, measured using electricity meters that comply with the requirements of the *Electricity and Gas Inspection Act* and the *Electricity and Gas Inspection Regulations*. (*solde exportateur*)

operator means a person who has the charge, management or control of a unit. (*exploitant*)

Reference Method means the document entitled *Reference Method for Source Testing: Quantification of Carbon Dioxide Releases by Continuous Emission Monitoring Systems from Thermal Power Generation*, June 2012, published by the Department of the Environment. (*méthode de référence*)

responsible person means an owner or operator of a unit. (*personne responsable*)

standard conditions means a temperature of 15˚C and a pressure of 101.325 kPa. (*conditions normales*)

unit means an assembly comprised of any equipment that is physically connected and that operates together to generate electricity, and

(a) must include at least a boiler or combustion engine, and

(b) may include duct burners and other combustion devices, heat recovery systems, steam turbines, generators, emission control devices and carbon capture and storage systems. (*groupe*)

useful thermal energy means energy in the form of steam or hot water that is destined for a use, other than

site intégré unique, sur lequel une activité industrielle est exercée. (*facility*)

méthode de référence Le document publié par le ministère de l'Environnement intitulé *Méthode de référence pour le contrôle à la source : quantification des émissions de dioxyde de carbone des centrales thermiques par un système de mesure et d'enregistrement en continu des émissions*, daté de juin 2012. (*Reference Method*)

méthode d'ECCC Le document intitulé *Exigences relatives à la quantification des gaz à effet de serre au Canada, Programme de déclaration des gaz à effet de serre*, publié en 2021 par le ministère de l'Environnement. (*GHGRP*)

moteur à combustion Tout moteur, à l'exception du moteur autopropulsé et du moteur conçu pour être propulsé tout en accomplissant sa fonction et qui, selon le cas :

a) fonctionne selon le cycle thermodynamique de Brayton et brûle du combustible fossile en vue de la production d'une quantité nette de force motrice;

b) brûle du combustible fossile et qui utilise un mouvement alternatif en vue de la conversion d'énergie thermique en travail mécanique. (*combustion engine*)

NERC La North American Electric Reliability Corporation. (*NERC*)

personne responsable Le propriétaire ou l'exploitant d'un groupe. (*responsible person*)

solde exportateur Pour une année civile donnée, quantité d'électricité exportée par un groupe vers un réseau électrique assujetti aux normes de la NERC, exprimée en GWh, moins la quantité d'électricité importée par un groupe d'un réseau électrique assujetti aux normes de la NERC, exprimée en GWh, quantifiée à l'aide de compteurs d'électricité qui sont conformes aux exigences de la *Loi sur l'inspection de l'électricité et du gaz* et du *Règlement sur l'inspection de l'électricité et du gaz*. (*net exports*)

système de gazéification du charbon S'entend notamment d'un système de gazéification du charbon qui est en partie souterrain. (*coal gasification system*)

système de mesure et d'enregistrement en continu des émissions ou ***SMECE*** Équipement destiné à l'échantillonnage, au conditionnement et à l'analyse d'émissions provenant d'une source donnée, ainsi qu'à

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the generation of electricity, that would have required the consumption of energy in the form of fuel or electricity had that steam or hot water not been used. (*énergie thermique utile*)

l'enregistrement de données concernant ces émissions. (*continuous emission monitoring system* or *CEMS*)

vérificateur Personne physique qui, à la fois :

a) est indépendante de la personne responsable faisant l'objet de la vérification;

b) possède des connaissances et de l'expérience en ce qui touche :

(i) la certification, l'exploitation et la vérification de l'exactitude relative des systèmes de mesure et d'enregistrement en continu des émissions,

(ii) les procédures d'assurance de la qualité et de contrôle de la qualité relatives à ces systèmes. (*auditor*)

More than one owner or operator

(2) For the purposes of the definition of *facility*, if there is more than one owner or operator for the facility, those elements are only included in the definition of facility if there is at least one owner or operator in common.

Plus d'un propriétaire ou exploitant

(2) Pour l'application de la définition de *installation*, s'il y a plus d'un propriétaire ou exploitant en commun, les éléments visés à cette définition ne sont compris dans celle-ci que s'ils ont en commun un même propriétaire ou exploitant.

Carbon capture and storage

(3) Equipment that is connected only by a carbon capture and storage system is not considered physically connected for the purposes of the definition of *unit* in subsection (1). That carbon capture and storage system must be included in the description of each unit connected to it.

Captage et de stockage de carbone

(3) Les équipements qui sont raccordés uniquement par un système de captage et de stockage de carbone ne sont pas considérés comme étant raccordés physiquement pour l'application de la définition de *groupe*, au paragraphe (1). Le système de captage et de stockage de carbone est inclus dans la description de chacun des groupes auquel il est raccordé.

Interpretation of documents incorporated by reference

(4) For the purposes of interpreting documents that are incorporated by reference into these Regulations, "should" is to be read as "must" and any recommendation or suggestion is to be read as an obligation.

Interprétation des documents incorporés par renvoi

(4) Pour l'interprétation des documents incorporés par renvoi dans le présent règlement, toute mention de « should » ainsi que les recommandations et suggestions expriment une obligation.

Incorporation by reference

(5) Unless otherwise indicated, a reference to any document incorporated by reference into these Regulations, except the GHGRP, is incorporated as amended from time to time.

Incorporation par renvoi

(5) Sauf indication contraire, toute mention d'un document incorporé par renvoi dans le présent règlement constitue un renvoi au document avec ses modifications successives, à l'exception de la méthode d'ECCC.

Application

Specified units

3 These Regulations apply to a unit that, on or after January 1, 2025, meets the following criteria:

Champ d'application

Groupes visés

3 Le présent règlement s'applique à tout groupe qui, le 1er janvier 2025 ou après cette date, remplit les conditions suivantes :

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(a) has an electricity generation capacity of 25 MW or more;

(b) generates electricity using fossil fuel; and

(c) is connected to an electricity system that is subject to NERC standards.

Registration

Registration Report

4 (1) A responsible person must register the unit by submitting a registration report to the Minister that contains the information set out in Schedule 1

(a) in the case of a unit that has a commissioning date on or after January 1, 2025, within 60 days after the date on which the unit was commissioned; or

(b) in the case of all other units, by December 31, 2025.

Modification

(2) If a unit is modified, such as by adding or removing a piece of equipment or changing how equipment is physically connected, and that modification creates one or more new units, the responsible person must

(a) register any new unit by submitting a registration report to the Minister that contains the information set out in Schedule 1 within 30 days after the date on which the unit was created; and

(b) notify the Minister that either the original unit has ceased to generate electricity, in accordance with subsection 24(3), or has been modified, in accordance with section 25.

Registration number

(3) On receipt of the registration report, the Minister must assign a registration number to the unit and inform the responsible person of that registration number.

Net Exports Declaration

Declaration

5 (1) A responsible person may submit to the Minister a declaration, dated and signed by the responsible person or their authorized official, stating that net exports with

a) il a une capacité de production d'électricité d'au moins vingt-cinq MW;

b) il produit de l'électricité à partir de combustibles fossiles;

c) il est connecté à un réseau électrique assujetti aux normes de la NERC.

Enregistrement

Rapport d'enregistrement

4 (1) La personne responsable d'un groupe transmet au ministre pour fins d'enregistrement un rapport d'enregistrement comportant les renseignements visés à l'annexe 1 dans l'un des délais suivants :

a) dans le cas d'un groupe dont la date de mise en service est le 1er janvier 2025 ou postérieure à cette date, le soixantième jour après la date de mise en service;

b) dans les autres cas, le 31 décembre 2025.

Modification

(2) Si un groupe subit une modification, notamment par l'ajout ou le retrait d'une pièce d'équipement ou par une modification dans la façon dont les équipements sont raccordés ensemble, qui a pour effet de créer un ou plusieurs nouveaux groupes, la personne responsable, selon le cas :

a) enregistre tout nouveau groupe en transmettant au ministre un rapport d'enregistrement comportant les renseignements visés à l'annexe 1 au plus tard trente jours après la création du groupe;

b) transmet au ministre un avis de cessation définitive de production d'électricité conformément au paragraphe 24 (3) ou un avis de modification des renseignements conformément à l'article 25, selon le cas.

Numéro d'enregistrement

(3) Sur réception d'un rapport d'enregistrement, le ministre assigne un numéro d'enregistrement au groupe et informe la personne responsable de ce numéro.

Déclaration relative au solde exportateur

Déclaration

5 (1) La personne responsable peut transmettre au ministre une déclaration, datée et signée par elle ou son agent autorisé, portant que le solde exportateur du

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respect to their unit are less than or equal to 0 GWh and containing the following information:

(a) the unit's registration number, assigned by the Minister under subsection 4(3); and

(b) an attestation that the declaration is accurate and complete.

December 31

(2) The declaration must be submitted to the Minister on or before December 31 of the calendar year prior to the calendar year in which the prohibition set out in subsection 6(1) will apply to that unit.

Exemptions

(3) If a declaration has been submitted with respect to a unit, the responsible person is exempt from sections 6 to 24.

Short report

(4) A responsible person for a unit with respect to which a declaration has been submitted must submit a short report to the Minister, containing the information set out in sections 1 and 2 of Schedule 2 and the net exports for that unit for the calendar year, on or before the June 1 that follows the calendar year that is the subject of the report.

Exemption ends

(5) Subject to subsection (6), the exemptions in subsection (3) do not apply with respect to the unit if the unit has net exports that are greater than 0 GWh in any calendar year.

Emergency exemption

(6) If a unit has net exports that are greater than 0 GWh in a calendar year due to the quantity of electricity being exported from the unit during a period for which the Minister has issued an exemption for that unit under section 19 or an extension under section 20, the exemptions set out in subsection (3) will continue to apply.

Prohibition

Prohibition

6 (1) A responsible person, for a unit with respect to which net exports are greater than 0 GWh during a calendar year, must not emit CO_2 from the unit, from the combustion of fossil fuel, that has on average during that calendar year an emission intensity of more than 30 tonnes of CO_2 emissions/GWh of electricity generated,

groupe sera égal ou inférieur à zéro GWh. La déclaration contient ce qui suit :

a) le numéro d'enregistrement du groupe attribué par le ministre en vertu du paragraphe 4(3);

b) une attestation que la déclaration est véridique et complète.

31 décembre

(2) La déclaration est transmise au ministre au plus tard le 31 décembre de l'année civile précédant celle de l'application de l'interdiction prévue au paragraphe 6(1) au groupe.

Exemptions

(3) La déclaration a pour effet d'exempter la personne responsable de l'application des articles 6 à 24.

Rapport abrégé

(4) La personne responsable d'un groupe à l'égard duquel une déclaration a été transmise au ministre transmet à celui-ci un rapport abrégé contenant les renseignements visés aux articles 1 et 2 de l'annexe 2 et les données sur le solde exportateur du groupe pour l'année civile au plus tard le 1er juin qui suit l'année civile faisant l'objet du rapport.

Fin des exemptions

(5) Sous réserve du paragraphe (6), les exemptions visées au paragraphe (3) deviennent inapplicables au groupe si le solde exportateur du groupe est supérieur à zéro GWh au cours de toute année civile.

Exemption en cas d'urgence

(6) Si le solde exportateur du groupe est supérieures à zéro GWh au cours d'une année civile en raison de la quantité d'électricité qu'il exporte au cours d'une période visée par une exemption accordée par le ministre en application de l'article 19 ou prolongée par celui-ci en application de l'article 20, les exemptions visées au paragraphe (3) continuent à s'appliquer.

Interdiction

Interdiction

6 (1) Il est interdit à la personne responsable d'un groupe dont le solde exportateur est supérieur à zéro GWh au cours d'une année civile de rejeter du CO_2 provenant de la combustion de combustibles fossiles par le groupe dont l'intensité d'émission est supérieure à 30 tonnes d'émissions de CO_2/GWh d'électricité produite en

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determined in accordance with sections 7 to 18, as applicable.

Exception — carbon capture and storage

(2) Despite subsection (1), a responsible person, for a unit with respect to which net exports are greater than 0 GWh, may, until December 31, 2039, emit from the unit CO_2 from the combustion of fossil fuel that has, on average during the calendar year, an emission intensity no more than 40 tonnes of CO_2 emissions/GWh of electricity generated, determined in accordance with sections 7 to 18, as applicable, if

(a) the unit includes a carbon capture and storage system that started operating within the last seven calendar years; and

(b) the responsible person for that unit has submitted, with the annual report, documentation demonstrating that the unit operated at or below 30 tonnes of CO_2 emissions/GWh for two periods of at least 12 continuous hours, with at least four months between those two periods, in the calendar year for which the annual report is submitted.

Exception — hours

(3) Despite subsection (1), a responsible person may, for a unit that has not combusted coal during the calendar year and with respect to which net exports are greater than 0 GWh, emit from that unit up to 150 kilotonnes of CO_2 in a calendar year, determined in accordance with section 8, if the unit operates for 450 hours or less during that calendar year, not including any hours the unit operates and CO_2 the unit emits during a period for which the Minister has issued an exemption under section 19 or an extension under section 20.

Start of prohibition

(4) The responsible person for a unit must meet the emission intensity limit set out in subsection (1), beginning

(a) January 1, 2035, with respect to a unit that

(i) has a commissioning date on or after January 1, 2025,

(ii) has increased its electricity generation capacity by 10% or more since submitting the registration report for the unit, or

(iii) combusts coal;

moyenne au cours de cette année civile, celle-ci étant déterminée conformément aux articles 7 à 18 selon le cas.

Exception — captage et stockage de carbone

(2) Malgré le paragraphe (1), la personne responsable d'un groupe dont le solde exportateur est supérieur à zéro GWh au cours d'une année civile donnée peut, au plus tard le 31 décembre 2039, rejeter du CO_2 provenant de la combustion de combustibles fossiles par le groupe dont l'intensité d'émission est inférieure ou égale à 40 tonnes d'émissions de CO_2/GWh d'électricité produite, intensité déterminée aux termes des articles 7 à 18, selon le cas, si :

a) le groupe comprend un système de captage et de stockage de carbone qui a commencé à fonctionner il y a au plus sept ans;

b) la personne responsable transmet, avec le rapport annuel, les documents établissant que le groupe a fonctionné, au cours de l'année civile faisant l'objet du rapport annuel, à une intensité inférieure ou égale à 30 tonnes d'émissions de CO_2/GWh pendant deux périodes d'au moins douze heures consécutives, ces périodes étant séparées d'au moins quatre mois.

Exception — heures

(3) Malgré le paragraphe (1), la personne responsable d'un groupe qui n'a pas brûlé de charbon au cours de l'année civile et qui a solde exportateur supérieur à zéro GWh peut rejeter une quantité maximale de 150 kilotonnes de CO_2, celle-ci étant déterminée conformément à l'article 8, si le groupe fonctionne pendant au plus 450 heures au cours de cette année civile, compte non tenu des émissions produites et du nombre d'heures de fonctionnement du groupe au cours de toute période visée par une exemption accordée par le ministre en application de l'article 19 ou prolongée par celui-ci en application de l'article 20 .

Début de l'interdiction

(4) La personne responsable est tenue de respecter la limite d'intensité d'émission prévue au paragraphe (1) à compter :

a) du 1er janvier 2035 dans le cas d'un groupe qui est dans l'une ou l'autre des situations suivantes :

(i) il est mis en service le 1er janvier 2025 ou après cette date,

(ii) il a augmenté sa capacité de production d'électricité de 10 % ou plus depuis la date d'envoi du rapport d'enregistrement,

(iii) il brûle du charbon;

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(b) in the case of a boiler unit referred to in subsection 3(4) of the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*, the later of

(i) January 1 of the calendar year the prohibition set out in subsection 4(2) of those Regulations begins to apply to the unit, as determined under that subsection; or

(ii) January 1, 2035, or

(c) January 1 of the calendar year following the unit's end of prescribed life, with respect to all other units.

Definition — prescribed life

(5) For the purposes of paragraph (4)(c), prescribed life means the period that begins on the commissioning date and ends on the later of

(a) December 31 of the calendar year that is 20 years after the commissioning date, and

(b) December 31, 2034.

Quantification

Emission Intensity

Emission intensity

7 (1) The emission intensity of a unit is determined by the formula

E ÷ G

where

E is the quantity of CO_2 emissions attributed to a unit, during the calendar year, expressed in tonnes, determined in accordance with section 8; and

G is the quantity of electricity generated by the unit during the calendar year, expressed in GWh, determined in accordance with subsection 18(1).

Negative number

(2) For the purposes of the formula in subsection (1), 0 should be used for the element E if the determination under section 8 results in a negative number.

b) dans le cas d'un groupe chaudière visé au paragraphe 3(4) du *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel*, la plus tardive des dates suivantes :

(i) le 1er janvier de l'année à partir de laquelle l'interdiction prévue au paragraphe 4(2) du même règlement s'applique au groupe, celle-ci étant déterminée aux termes de ce paragraphe,

(ii) le 1er janvier 2035;

c) dans les autres cas, du 1er janvier de l'année civile suivant celle au cours de laquelle la vie réglementaire du groupe prend fin.

Définition — vie réglementaire

(5) Pour l'application de l'alinéa (4)c), vie réglementaire s'entend de la période commençant à la date de mise en service du groupe et se terminant à la plus tardive des dates suivantes :

a) le 31 décembre de l'année civile qui tombe vingt ans après la date de mise en service;

b) le 31 décembre 2034.

Quantification

Intensité des émissions

Intensité des émissions

7 (1) L'intensité des émissions d'un groupe est déterminée conformément à la formule suivante :

E ÷ G

où :

E représente la quantité d'émissions de CO_2, exprimée en tonnes, attribuée à un groupe au cours de l'année civile, déterminée conformément à l'article 8;

G la quantité d'électricité, exprimée en GWh, produite par le groupe au cours de l'année civile, déterminée conformément au paragraphe 18(1) .

Valeur négative

(2) Il est entendu que si le résultat de la détermination de la variable E dans la formule prévue au paragraphe (1) en application de l'article 8 est une valeur négative, elle est alors zéro.

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Quantity of CO_2 Emissions

Quantification Methods

Quantification of emissions

8 (1) The quantity of CO_2 emissions attributed to a unit during the calendar year is determined by the formula

$$E_u - E_{th} - E_{ccs} + E_{ext} - E_{ec}$$

where

E_u is the quantity of CO_2 emissions, expressed in tonnes, during the calendar year from the combustion of fossil fuel in the unit, as determined in accordance with subsection (3) and, as applicable, section 9, 10 or 13;

E_{th} is the quantity of CO_2 emissions, expressed in tonnes, attributable to the production of useful thermal energy by the unit, during the calendar year, calculated in accordance with section 15;

E_{ccs} is the quantity of CO_2 captured from the unit during the calendar year and stored in a storage project, expressed in tonnes, determined in accordance with section 16;

E_{ext} is the quantity of CO_2 emitted from the production of the hydrogen fuel or the purchased or transferred steam used by the unit to generate electricity, during the calendar year, expressed in tonnes, determined in accordance with section 17; and

E_{ec} is the quantity of CO_2 emitted from the unit during any period in the calendar year for which the Minister has issued an exemption under section 19 or an extension under section 20, expressed in tonnes, determined in accordance with subsection (2).

Calculation of E_{ec}

(2) The element E_{ec} is the difference between the sum of E_u and E_{ext} and the sum of E_{th} and E_{ccs} calculated in accordance with sections 9, 10, 13, 15 to 17 and 19, as applicable, but the reference to calendar year is replaced with the period during the calendar year for which the Minister has issued an exemption under section 19 or an extension under section 20.

Quantification method for E_u

(3) The quantity of CO_2 emissions resulting from the combustion of fossil fuel in a unit in a calendar year (E_u) must be determined in accordance with

Quantité d'émissions de CO_2

Méthodes de quantification

Quantification des émissions

8 (1) La quantité d'émissions de CO_2 attribuée à un groupe au cours de l'année civile est déterminée conformément à la formule suivante :

$$E_g - E_{th} - E_{csc} + E_{ext} - E_{su}$$

où :

E_g représente la quantité d'émissions de CO_2, exprimée en tonnes, provenant de la combustion de combustibles fossiles par le groupe, au cours de l'année civile, et déterminée conformément au paragraphe (3) et, selon le cas, à l'article 9, 10 ou 13;

E_{th} la quantité d'émissions de CO_2, exprimée en tonnes, attribuée à la production d'énergie thermique utile par le groupe, au cours de l'année civile, et déterminée en application de l'article 15;

E_{csc} la quantité de CO_2, exprimée en tonnes, captée à partir du groupe, au cours de l'année civile, et déterminée conformément à l'article 16;

E_{ext} la quantité de CO_2, exprimée en tonnes, provenant de la production d'hydrogène ou de vapeur qui est utilisé par le groupe pour produire de l'électricité, au cours de l'année civile, déterminée conformément à l'article 17;

E_{su} la quantité de CO_2, exprimée en tonnes, émise par le groupe au cours d'une période, pendant l'année civile, visée par une exemption accordée par le ministre en application de l'article 19 ou prolongée par celui-ci en application de l'article 20, et déterminée conformément au paragraphe (2).

Calcul de la variable E_{su}

(2) La variable E_{su} représente la différence entre la somme des variables E_g et E_{ext} et la somme des variables E_{th} et E_{csc} calculée conformément aux articles 9, 10, 13, 15 à 17 et 19, selon le cas, calcul dans lequel l'année civile est remplacée par la période au cours de celle-ci qui est visée par une exemption accordée par le ministre en application de l'article 19 ou prolongée par celui-ci en application de l'article 20.

Méthodes de quantification pour E_g

(3) La quantité d'émissions de CO_2 provenant de la combustion de combustibles fossiles attribuée à un groupe au cours d'une année civile (E_g) est déterminée, selon le cas :

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(a) section 9, in the case of a unit that combusted fuel from a coal gasification system during the calendar year;

(b) section 10, in the case of a unit that combusted biomass and combusted fuel from a coal gasification system during the calendar year;

(c) section 13, in the case of a unit that combusted biomass, but did not combust fuel from a coal gasification system, during the calendar year; and

(d) section 9 or 13, in any other case.

Carbon capture and storage

(4) For the purposes of the element E_{ccs} in subsections (1) and (2), the quantity of CO_2 may only be included in that description if it has been permanently stored in a storage project that meets the following criteria:

(a) the geological site into which the CO_2 is injected is

(i) a deep saline aquifer for the sole purpose of storage of CO_2, or

(ii) a depleted oil reservoir for the purpose of enhanced oil recovery; and

(b) the CO_2 stored for the purposes of the project is captured, transported and stored in accordance with the laws applicable to Canada or a province or applicable to the United States or one of its states.

Continuous Emission Monitoring System

Quantification with CEMS

9 Subject to section 11, for the purposes of paragraph 8(3)(a), the quantity of CO_2 emissions must be measured using a CEMS and determined in accordance with Sections 7.1 to 7.7 of the Reference Method. This also applies with respect to a responsible person that, in accordance with paragraph 8(3)(d), opts to quantify emissions in accordance with this section.

Unit combusting biomass

10 (1) Subject to section 11, for the purposes of paragraph 8(3)(b), the quantity of CO_2 emissions must be

a) conformément à l'article 9 si le groupe a brûlé du combustible provenant d'un système de gazéification de charbon au cours de l'année civile;

b) conformément à l'article 10 si le groupe a brûlé à la fois de la biomasse et du combustible provenant d'un système de gazéification de charbon au cours de l'année civile;

c) conformément à l'article 13 si le groupe a brûlé de la biomasse et n'a pas brûlé de combustible provenant d'un système de gazéification de charbon au cours de l'année civile;

d) soit conformément aux articles 9 ou 13 dans tout autre cas.

Captage et de stockage de carbone

(4) Seule peut être comptabilisée sous la variable E_{csc} visée aux paragraphes (1) et (2) la quantité de CO_2 stockée de façon permanente dans le cadre d'un projet de stockage qui respecte les critères suivants :

a) le CO_2 est injecté dans un site de stockage géologique :

(i) soit dans le seul but de le stocker dans un aquifère salin profond,

(ii) soit dans le but de permettre la récupération assistée d'hydrocarbures dans un gisement de pétrole épuisé;

b) le CO_2 stocké aux fins du projet est capté, transporté et stocké conformément aux lois fédérales ou provinciales applicables ou aux lois applicables des États-Unis ou de l'un de ses États.

Système de mesure et d'enregistrement en continu des émissions

Mesure à l'aide d'un SMECE

9 Sous réserve de l'article 11, pour l'application de l'alinéa 8(3)a), la quantité d'émissions de CO_2 est mesurée à l'aide d'un SMECE et calculée conformément aux sections 7.1 à 7.7 de la méthode de référence. Il en est de même pour l'application de l'alinéa 8(3)d) lorsque la personne responsable choisit de mesurer la quantité d'émissions conformément au présent article.

Groupe brûlant de la biomasse

10 (1) Sous réserve de l'article 11, pour l'application de l'alinéa 8(3)b), la quantité d'émissions de CO_2 d'un

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quantified using a CEMS and must be determined by the formula

$$E_{comb} \times (V_{ff} \div V_T) - E_s$$

where

E_{comb} is the quantity of CO_2 emissions from the unit, expressed in tonnes, during the calendar year from the combustion of fossil fuel and biomass, as measured by the CEMS, and calculated in accordance with Sections 7.1 to 7.7 of the Reference Method;

V_{ff} is the volume of CO_2 emissions released from the combustion of fossil fuel in the unit during the calendar year, expressed in m^3, at standard conditions, and determined by the formula

$$\sum_{i=1}^{n} Q_i \times F_{c,i} \times HHV_i$$

where

i is the ith fossil fuel type combusted in the unit during the calendar year, where "i" goes from 1 to n and where n is the number of fossil fuels so combusted,

Q_i is the quantity of fossil fuel type "i" combusted in the unit during the calendar year, determined

(a) for a gaseous fuel, in the same manner used in the determination of V_f in the formula set out in paragraph 14(1)(a) and expressed in m^3 at standard conditions,

(b) for a liquid fuel, in the same manner used in the determination of V_f in the formula set out in paragraph 14(1)(b) and expressed in kL, and

(c) for a solid fuel, in the same manner used in the determination of M_f in the formula set out in paragraph 14(1)(c) and expressed in tonnes;

$F_{c,i}$ is the fuel-specific carbon-based F-factor for each fossil fuel type "i" — either the factor set out in Appendix A of the Reference Method, or for fuels not listed, the one determined in accordance with that Appendix — corrected to be expressed in m^3, at standard conditions, of CO_2/GJ, and

HHV_i is the higher heating value for each fossil fuel type "i" that is measured in accordance with subsection (2), or the default higher heating value, set out in column 2 of

groupe est mesurée à l'aide d'un SMECE et calculée conformément à la formule suivante :

$$E_{comb} \times (V_{cf} \div V_t) - E_s$$

où :

E_{comb} représente la quantité d'émissions de CO_2, exprimée en tonnes, par le groupe au cours de l'année civile, provenant de la combustion de combustibles fossiles et de biomasse, mesurée par le SMECE et calculée conformément aux sections 7.1 à 7.7 de la méthode de référence;

V_{cf} le volume d'émissions de CO_2 provenant de la combustion des combustibles fossiles par le groupe au cours de l'année civile, exprimé en m^3, mesuré dans des conditions normales et déterminé conformément à la formule suivante :

$$\sum_{i=1}^{n} Q_i \times F_{c,i} \times HHV_i$$

où :

i représente le i^e type de combustible fossile brûlé par le groupe au cours de l'année civile , où « i » est un chiffre de 1 à n, « n » étant le nombre de ces combustibles,

Q_i la quantité de combustible fossile de type « i » brûlé par le groupe au cours de l'année civile, déterminée, selon le cas :

a) pour les combustibles gazeux, de la même façon que la variable V_c dans la formule prévue à l'alinéa 14(1)a), cette quantité étant exprimée en m^3 et mesurée dans des conditions normales,

b) pour les combustibles liquides, de la même façon que la variable V_c dans la formule prévue à l'alinéa 14(1)b), cette quantité étant exprimée en kL,

c) pour les combustibles solides, de la même façon que la variable M_c dans la formule prévue à l'alinéa 14(1)c), cette quantité étant exprimée en tonnes,

$F_{c,i}$ le facteur de carbone propre à chaque combustible fossile de type « i », celui-ci étant le facteur prévu à l'annexe A de la méthode de référence ou, à défaut, celui qui est déterminé conformément à cette annexe, corrigé pour être exprimé en m^3 de CO_2/GJ mesuré dans des conditions normales,

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Schedule 3, for the fuel type, as set out in column 1;

V_T is the volume of CO_2 emissions released from combustion of fossil fuel and biomass in the unit during the calendar year determined by the formula

$$\sum_{t=1}^{n}[0.01 \times CO_{2w,t} \times Q_{w,t}]$$

where

t is the tth hour, where "t" goes from 1 to n and where n is the total number of hours during which the unit generated electricity in the calendar year,

$CO_{2w,t}$ is the average concentration of CO_2 in relation to all gases in the stack emitted from the combustion of fuel in the unit during each hour "t", during which the unit generated electricity in the calendar year — or, if applicable, a calculation made in accordance with Section 7.4 of the Reference Method of that average concentration of CO_2 based on a measurement of the concentration of oxygen (O_2) in those gases in the stack — expressed as a percentage on a wet basis, and

$Q_{w,t}$ is the average volumetric flow during that hour, measured on a wet basis by the stack gas volumetric flow monitor, expressed in m^3, at standard conditions; and

E_s is the quantity of CO_2 emissions, expressed in tonnes, that is released from the use of sorbent to control the emission of sulphur dioxide from the unit during the calendar year, determined by the formula

$$S \times R \times (44 \div MM_s)$$

where

S is the quantity of sorbent material, such as calcium carbonate ($CaCO_3$), expressed in tonnes,

R is the stoichiometric ratio, on a mole fraction basis, of CO_2 released on usage of one mole of sorbent material, which is equal to 1 if the sorbent material is $CaCO_3$, and

MM_s is the molecular mass of the sorbent material, which is equal to 100 if the sorbent material is $CaCO_3$.

HHV_i le pouvoir calorifique supérieur pour chaque type de combustible fossile de type « i », celui-ci étant déterminé conformément au paragraphe (2) ou le pouvoir calorifique supérieur par défaut mentionné à la colonne 2 de l'annexe 3 pour le type de combustible visé à la colonne 1;

V_t le volume d'émissions de CO_2 provenant de la combustion de combustibles fossiles et de biomasse par le groupe au cours de l'année civile, déterminé conformément à la formule suivante :

$$\sum_{t=1}^{n}[0,01 \times CO_{2h,t} \times Q_{h,t}]$$

où :

t représente la t^e heure, où « t » est un chiffre de 1 à n, « n » étant le nombre total d'heures durant lesquelles le groupe a produit de l'électricité au cours de l'année civile,

$CO_{2h,t}$ la concentration moyenne d'émissions de CO_2 par rapport à la totalité des gaz de cheminée provenant de la combustion de combustibles par le groupe pour chaque heure « t » de production d'électricité au cours de l'année civile — ou, le cas échéant, le résultat du calcul effectué conformément à l'article 7.4 de la méthode de référence à partir d'une mesure de la concentration d'oxygène (O_2) dans ces gaz de cheminée —, exprimée en pourcentage de CO_2 sur une base humide,

$Q_{h,t}$ le débit volumétrique moyen durant l'heure en cause, exprimé en m^3 et mesuré dans des conditions normales sur une base humide par un appareil de mesure du débit volumétrique placé sur la cheminée;

E_s la quantité, exprimée en tonnes, d'émissions de CO_2 provenant du sorbant utilisé pour contrôler les émissions de dioxyde de soufre par le groupe au cours de l'année civile, calculée conformément à la formule suivante :

$$S \times R \times (44 \div MM_s)$$

où :

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S représente la quantité de sorbant — notamment le carbonate de calcium ($CaCO_3$) —, exprimée en tonnes,

R le rapport stœchiométrique — selon la fraction molaire — de CO_2 attribuable à une mole de sorbant, lequel est 1 si le sorbant est du $CaCO_3$,

MM_s la masse moléculaire du sorbant, laquelle est 100 si le sorbant est du $CaCO_3$.

Higher heating value

(2) The higher heating value of a fuel is to be measured

(a) for a gaseous fuel,

(i) in accordance with the following standards, as applicable

(A) ASTM D1826-94(2017), entitled *Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter*,

(B) ASTM D3588-98(2017), entitled *Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels*,

(C) ASTM D4891-13, entitled *Standard Test Method for Heating Value of Gases in Natural Gas and Flare Gases Range by Stoichiometric Combustion*,

(D) Gas Processors Association Standard 2172 - 14, entitled *Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer*, and

(E) Gas Processors Association Standard 2261 - 13, entitled *Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography*, or

(ii) by means of a direct measuring device that measures the higher heating value of the fuel, but if the measuring device provides only lower heating values, those lower heating values must be converted to higher heating values; and

(b) for a liquid fuel that is

(i) an oil or a liquid fuel derived from waste, in accordance with

Pouvoir calorifique supérieur

(2) Le pouvoir calorifique supérieur d'un combustible est déterminé :

a) dans le cas des combustibles gazeux :

(i) soit conformément à l'une ou l'autre des normes ci-après applicable au combustible en cause :

(A) la norme ASTM D1826-94(2017) intitulée *Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter*,

(B) la norme ASTM D3588-98(2017) intitulée *Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels*,

(C) la norme ASTM D4891-13 intitulée *Standard Test Method for Heating Value of Gases in Natural Gas and Flare Gases Range by Stoichiometric Combustion*,

(D) la norme 2172-14 de la Gas Processors Association intitulée *Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer*,

(E) la norme 2261-13 de la Gas Processors Association intitulée *Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography*,

(ii) soit à l'aide d'un instrument de mesure directe, mais s'il ne détermine que le pouvoir calorifique inférieur, celui-ci est converti en pouvoir calorifique supérieur;

b) dans le cas des combustibles liquides :

(i) s'agissant d'huiles et de dérivés de déchets, conformément à l'une ou l'autre des normes suivantes :

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(A) ASTM D240-17, entitled *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter*, or

(B) ASTM D4809-13, entitled *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)*, and

(ii) any other liquid fuel type, in accordance with an applicable ASTM standard for the measurement of the higher heating value of the fuel type or, if no such ASTM standard applies, in accordance with an applicable internationally recognized method.

(A) la norme ASTM D240-17 intitulée *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter*,

(B) la norme ASTM D4809-13 intitulée *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)*,

(ii) s'agissant d'autres combustibles liquides, conformément à la norme ASTM applicable au type de combustible en cause ou, en l'absence d'une telle norme, conformément à toute méthode applicable qui est reconnue à l'échelle internationale.

Multiple CEMS per unit

11 (1) For the purposes of sections 9 and 10, the total quantity of CO_2 emissions from a unit equipped with multiple CEMS is determined by adding together the quantity of CO_2 emissions measured for each CEMS.

Plusieurs SMECE par groupe

11 (1) Pour l'application des articles 9 et 10, la quantité totale d'émissions de CO_2 par tout groupe doté de plusieurs SMECE est égale à la somme des quantités d'émissions de CO_2 mesurées pour chaque SMECE.

Units sharing common stack

(2) If a unit is located at a facility where there is one or more other units and a CEMS measures emissions from that unit and other units at a common stack rather than at the exhaust duct of that unit and of each of those other units that brings those emissions to the common stack, then the quantity of emissions attributable to that unit is determined based on the ratio of the heat input of that unit to the total of the heat input of that unit and of all of those other units sharing the common stack in accordance with the formula

$$\left[\frac{\sum_{j=1}^{y} Q_{u,j} \times HHV_{u,j}}{\sum_{i=1}^{x}\sum_{j=1}^{y} Q_{i,j} \times HHV_{i,j}}\right] \times E$$

where

Plusieurs groupes utilisant une cheminée commune

(2) Si le groupe est situé à une installation où sont situés un ou plusieurs autres groupes, et qu'un SMECE est utilisé pour mesurer les émissions de ce groupe et celles d'autres groupes au point de rejet d'une cheminée commune plutôt qu'au conduit d'évacuation de chacun de ces groupes vers la cheminée commune, la quantité d'émissions attribuable au groupe en cause est calculée en fonction de la proportion de l'apport de chaleur du groupe en cause par rapport à celui de l'ensemble des groupes qui utilisent la cheminée commune, conformément à la formule suivante :

$$\left[\frac{\sum_{j=1}^{y} Q_{g,j} \times HHV_{g,j}}{\sum_{i=1}^{x}\sum_{j=1}^{y} Q_{i,j} \times HHV_{i,j}}\right] \times E$$

où :

$Q_{u,j}$ is the quantity of fuel type "j" combusted in that unit "u" during the calendar year, determined

(a) for a gaseous fuel, in the same manner as the one used in the determination of V_f in the formula set out in paragraph 14(1)(a) and expressed in m^3 at standard conditions,

(b) for a liquid fuel, in the same manner as the one used in the determination of V_f in the formula set out in paragraph 14(1)(b) and expressed in kL, and

(c) for a solid fuel, in the same manner as the one used in the determination of M_f in the formula set out in paragraph 14(1)(c) and expressed in tonnes;

$Q_{g,j}$ représente la quantité de combustible fossile de type « j » brûlé par le groupe en cause « g » au cours de l'année civile en cause, déterminée :

a) pour les combustibles gazeux, de la même façon que la variable V_c dans la formule prévue à l'alinéa 14(1)a), cette quantité étant exprimée en m^3 et mesurée dans des conditions normales,

b) pour les combustibles liquides, de la même façon que la variable V_c dans la formule prévue à l'alinéa 14(1)b), cette quantité étant exprimée en kL,

c) pour les combustibles solides, de la même façon que la variable M_c dans la formule prévue à

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$HHV_{u,j}$ is the higher heating value for each fossil fuel type "j" that is combusted in that unit "u" that is measured in accordance with subsection 10(2), or the default higher heating value, set out in column 2 of Schedule 3, for the fuel type, as set out in column 1;

j is the jth fuel type combusted during the calendar year in a unit where "j" goes from 1 to y and where y is the number of those fuel types;

$Q_{i,j}$ the quantity of fuel type "j" combusted in each unit "i" during the calendar year, determined for a gaseous fuel, a liquid fuel and a solid fuel, respectively, in the manner set out in the description of $Q_{u,j}$;

$HHV_{i,j}$ is the higher heating value for each fossil fuel type "j" that is combusted in that unit "i" that is measured in accordance with subsection 10(2), or the default higher heating value, set out in column 2 of Schedule 3, for the fuel type, as set out in column 1;

i is the ith unit, where "i" goes from 1 to x, and where x is the number of units that share a common stack; and

E is the quantity of CO_2 emissions, expressed in tonnes, from the combustion of all fuels in all the units that share a common stack during the calendar year, measured by a CEMS at the common stack, and calculated in accordance with Sections 7.1 to 7.7 of the Reference Method.

$HHV_{g,j}$ le pouvoir calorifique supérieur pour chaque type de combustible fossile de type « j » brûlé par le groupe « g », celui-ci étant déterminé conformément au paragraphe 10(2) ou mentionné à la colonne 2 de l'annexe 3 pour le type de combustible visé à la colonne 1;

j le j^{e} type de combustible brûlé au cours de l'année civile par le groupe, où « j » est un chiffre de 1 à y, « y » étant le nombre de types de combustible;

$Q_{i,j}$ la quantité de combustible du type « j » brûlé par chaque groupe « i » au cours de l'année civile, déterminée pour les combustibles gazeux, les combustibles liquides et les combustibles solides, respectivement, de la manière prévue pour la variable $Q_{g,j}$;

$HHV_{i,j}$ le pouvoir calorifique supérieur pour chaque type de combustible fossile de type « j » brûlé par chaque groupe « i », celui-ci étant déterminé conformément au paragraphe 10(2) ou mentionné à la colonne 2 de l'annexe 3 pour le type de combustible visé à la colonne 1;

i le i^{e} groupe, où « i » est un chiffre de 1 à x, « x » étant le nombre de groupes qui utilisent la cheminée commune;

E la quantité, exprimée en tonnes, d'émissions de CO_2 provenant de la combustion de tous les combustibles par tous les groupes qui utilisent la cheminée commune au cours de l'année civile, mesurée par un SMECE installé à la cheminée commune et calculée conformément aux sections 7.1 à 7.7 de la méthode de référence.

If using CEMS

12 (1) If a CEMS is being used to measure CO_2 emissions, the responsible person must ensure that the requirements set out in the Reference Method are met.

Utilisation d'un SMECE

12 (1) La personne responsable qui utilise un SMECE pour mesurer les émissions de CO_2 veille à ce que les exigences prévues dans la méthode de référence soient suivies.

Certification of CEMS

(2) The responsible person must certify the CEMS in accordance with Section 5 of the Reference Method, before it is used for the purposes of these Regulations.

Homologation du SMECE

(2) La personne responsable homologue le SMECE conformément à la section 5 de la méthode de référence avant son utilisation pour l'application du présent règlement.

Auditor's report

(3) For each calendar year during which the responsible person used a CEMS, they must obtain a report, signed by the auditor, that contains the information required by

Rapport du vérificateur

(3) Pour chaque année civile au cours de laquelle la personne responsable a utilisé un SMECE, elle obtient un rapport comportant les renseignements requis à l'annexe

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Schedule 4 and submit that report to the Minister with the annual report referred to in subsection 24(1).

Fuel-based Method

Quantification

13 The quantity of CO_2 emissions resulting from the combustion of fossil fuels in a unit in a calendar year is determined by the formula

$$\sum_{i=1}^{n} E_i + E_s$$

where

i is the ith fossil fuel type that is combusted in the calendar year in a unit, where "i" goes from 1 to n and where n is the number of those fossil fuel types;

E_i is the quantity of CO_2 emissions that is attributable to the combustion of fossil fuels of type "i" in the unit in the calendar year, expressed in tonnes, as determined for that fuel type in accordance with section 14; and

E_s is the quantity of CO_2 emissions that is released from the sorbent used to control the emission of sulphur dioxide from the unit in the calendar year, expressed in tonnes, as determined by the formula

$$S \times R \times (44 \div MM_s)$$

where

S is the quantity of sorbent material, such as calcium carbonate ($CaCO_3$), expressed in tonnes,

R is the stoichiometric ratio, on a mole fraction basis, of CO_2 released on usage of 1 mole of sorbent material, which is equal to 1 if the sorbent material is $CaCO_3$, and

MM_s is the molecular mass of the sorbent material, which is equal to 100 if the sorbent material is $CaCO_3$.

Measured carbon content

14 (1) The quantity of CO_2 emissions that is attributable to the combustion of a fossil fuel in a unit in a calendar year is determined by one of the following formulas, as applicable

4, signé par le vérificateur, et le transmet au ministre avec le rapport annuel prévu au paragraphe 24(1).

Quantification fondée sur le combustible brûlé

Quantification

13 La quantité d'émissions de CO_2 provenant de la combustion de combustibles fossiles par un groupe, au cours d'une année civile, est calculée conformément à la formule suivante :

$$\sum_{i=1}^{n} E_i + E_s$$

où :

i représente le i^e type de combustible fossile brûlé par le groupe au cours de l'année civile, où « i » est un chiffre de 1 à n, « n » étant le nombre de types de combustible fossile brûlé;

E_i la quantité d'émissions de CO_2, exprimée en tonnes, qui est attribuable à la combustion de combustibles fossiles de type « i » par le groupe au cours de l'année civile et qui est calculée selon le type de combustible conformément à l'article 14;

E_s la quantité d'émissions de CO_2, exprimée en tonnes, qui provient du sorbant utilisé pour contrôler les émissions de dioxyde de soufre par le groupe au cours de l'année civile et qui est calculée conformément à la formule suivante :

$$S \times R \times (44 \div MM_s)$$

où :

S représente la quantité de sorbant — tel que le carbonate de calcium ($CaCO_3$) —, exprimée en tonnes,

R le rapport stœchiométrique — selon la fraction molaire — de CO_2 attribuable à une mole de sorbant, lequel est de 1 si le sorbant est du $CaCO_3$,

MM_s la masse moléculaire du sorbant, laquelle est de 100 si le sorbant est du $CaCO_3$.

Contenu en carbone mesuré

14 (1) La quantité d'émissions de CO_2 qui est attribuable à la combustion de combustibles fossiles par le groupe au cours d'une année civile est calculée conformément à celle des formules ci-après qui s'applique :

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(a) for a gaseous fuel,

$$V_f \times CC_A \times (MM_A \div MV_{cf}) \times 3.664 \times 0.001$$

where

V_f is the volume of the fuel combusted in the calendar year, determined using flow meters, expressed in m^3, at standard conditions,

CC_A is the weighted average of the carbon content of the fuel, determined in accordance with subsection (2), expressed in kg of carbon per kg of the fuel,

MM_A is the average molecular mass of the fuel, determined based on fuel samples taken in accordance with section 21, expressed in kg per kg-mole of the fuel, and

MV_{cf} is the molar volume conversion factor of 23.645 m^3, at standard conditions, per kg-mole of the fuel at standard conditions;

(b) for a liquid fuel,

$$V_f \times CC_A \times 3.664$$

where

V_f is the volume of the fuel combusted in the calendar year, determined using flow meters, expressed in kL, and

CC_A is the weighted average of the carbon content of the fuel, determined in accordance with subsection (2), at the same temperature as that used in the determination of V_f, expressed in tonnes of carbon per kL of the fuel; and

(c) for a solid fuel,

$$M_f \times CC_A \times 3.664$$

where

M_f is the mass of the fuel combusted in the calendar year, determined, as the case may be, on a wet or dry basis using a measuring device, expressed in tonnes, and

CC_A is the weighted average of the carbon content of the fuel, determined in accordance with subsection (2), on the same wet or dry basis as that used in the determination of M_f, expressed in kg of carbon per kg of the fuel.

a) dans le cas de combustibles gazeux :

$$V_c \times CC_M \times (MM_M \div MV_{fc}) \times 3{,}664 \times 0{,}001$$

où :

V_c représente le volume du combustible brûlé au cours de l'année civile, exprimé en m^3 et mesuré dans des conditions normales et déterminé à l'aide de débitmètres,

CC_M la moyenne pondérée du contenu en carbone du combustible, exprimée en kg de carbone par kg de combustible, calculée conformément au paragraphe (2),

MM_M la masse moléculaire moyenne du combustible, exprimée en kg par kg-mole de combustible, déterminée à partir des échantillons de combustible prélevés conformément à l'article 21,

MV_{fc} le facteur de conversion du volume molaire, soit 23,645 m^3, mesuré dans des conditions normales, par kg-mole de combustible mesuré dans des conditions normales;

b) dans le cas de combustibles liquides :

$$V_c \times CC_M \times 3{,}664$$

où :

V_c représente le volume du combustible brûlé au cours de l'année civile, exprimé en kL et déterminé à l'aide de débitmètres,

CC_M la moyenne pondérée du contenu en carbone du combustible, exprimée en tonnes de carbone par kL de combustible et calculée conformément au paragraphe (2) à la même température que celle choisie pour déterminer la variable V_c;

c) dans le cas de combustibles solides :

$$M_c \times CC_M \times 3{,}664$$

où :

M_c représente la masse du combustible brûlé au cours de l'année civile, déterminée, selon le cas, sur une base sèche ou humide, à l'aide d'un instrument de mesure et exprimée en tonnes,

CC_M la moyenne pondérée du contenu en carbone du combustible, exprimée en kg de carbone par kg de combustible et calculée conformément au paragraphe (2) sur la même base sèche ou humide que celle qui a été choisie pour déterminer la variable M_c.

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Weighted average

(2) The weighted average "CC_A" referred to in paragraphs (1)(a) to (c) is determined by the formula

$$\frac{\sum_{i=1}^{n} CC_i \times Q_i}{\sum_{i=1}^{n} Q_i}$$

where

CC_i is the carbon content of each sample or composite sample, as the case may be, of the fuel for the ith sampling period, expressed for gaseous fuels, liquid fuels and solid fuels, respectively, in the same unit of measure as that set out in CC_A, as provided by the supplier of the fuel to the responsible person or, if not so provided, as determined by the responsible person in the following manner:

(a) for a gaseous fuel,

(i) in accordance with the following standards for the measurement of the carbon content of the fuel, as applicable

(A) ASTM D1945-14, entitled *Standard Test Method for Analysis of Natural Gas by Gas Chromatography*,

(B) ASTM UOP539-12, entitled *Refinery Gas Analysis by Gas Chromatography*,

(C) ASTM D7833-14, entitled *Standard Test Method for Determination of Hydrocarbons and Non-Hydrocarbon Gases in Gaseous Mixtures by Gas Chromatography*, and

(D) API Technical Report 2572, 1st edition, published in May 2013 and entitled *Carbon Content, Sampling, and Calculation*, or

(ii) by means of a direct measuring device that measures the carbon content of the fuel,

(b) for a liquid fuel, in accordance with the following standards or methods for the measurement of the carbon content of the fuel, as applicable

(i) API Technical Report 2572, 1st edition, published in May 2013 and entitled *Carbon Content, Sampling, and Calculation*,

(ii) ASTM D5291-16, entitled *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants*,

(iii) the ASTM standard that applies to the type of fuel, or

Moyenne pondérée

(2) La moyenne pondérée « CC_M » visée aux alinéas (1)a) à c) est calculée conformément à la formule suivante :

$$\frac{\sum_{i=1}^{n} CC_i \times Q_i}{\sum_{i=1}^{n} Q_i}$$

où :

CC_i représente le contenu en carbone de chaque échantillon ou échantillon composite, selon le cas, de combustible pour la i^e période d'échantillonnage, exprimé pour un combustible gazeux, liquide et solide, respectivement, dans la même unité de mesure que celle prévue pour la variable CC_M, qui soit est fourni à la personne responsable par le fournisseur du combustible, ou sinon, qui est établi par la personne responsable de la façon suivante :

a) dans le cas des combustibles gazeux :

(i) soit conformément à l'une des normes applicables ci-après qui permet d'en mesurer le contenu en carbone :

(A) la norme ASTM D1945-14 intitulée *Standard Test Method for Analysis of Natural Gas by Gas Chromatography*,

(B) la norme ASTM UOP539-12 intitulée *Refinery Gas Analysis by Gas Chromatography*,

(C) la norme ASTM D7833-14 intitulée *Standard Test Method for Determination of Hydrocarbons and Non-Hydrocarbon Gases in Gaseous Mixtures by Gas Chromatography*,

(D) le document intitulé API Technical Report 2572, *Carbon Content, Sampling, and Calculation*, 1re édition, publié en mai 2013,

(ii) soit à l'aide d'un instrument de mesure directe,

b) dans le cas des combustibles liquides, conformément à l'une des normes ou méthodes applicables ci-après qui permet d'en mesurer le contenu en carbone :

(i) le document intitulé API Technical Report 2572, *Carbon Content, Sampling, and Calculation*, 1re édition, publié en mai 2013,

(ii) la norme ASTM D5291-16 intitulée *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants*,

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(iv) if no ASTM standard applies, an applicable internationally recognized method, and

(c) for a solid fuel, on the same wet or dry basis as that used in the determination of CC_A, in accordance with,

(i) for a solid fuel derived from waste, ASTM E777-08, entitled *Standard Test Method for Carbon and Hydrogen in the Analysis Sample of Refuse-Derived Fuel*, and

(ii) for any other solid fuel, the following standard or method for the measurement of the carbon content of the fuel, as applicable:

(A) the ASTM standard that applies to the type of fuel, and

(B) if no ASTM standard applies, an applicable internationally recognized method;

i is the ith sampling period that is referred to in section 21, where "i" goes from 1 to n and where n is the number of those sampling periods; and

Q_i is the volume or mass, as the case may be, of the fuel combusted during the ith sampling period, expressed

(a) in m^3, at standard conditions, for a gaseous fuel,

(b) in kL for a liquid fuel, and

(c) in tonnes for a solid fuel, on the same wet or dry basis as that used in the determination of CC_A.

Useful Thermal Energy

Emissions – useful thermal energy (E_{th})

15 The quantity of CO_2 emitted by the unit attributable to the production of useful thermal energy by the unit is determined by the formula

$$H_{pnet} \times b_{EI}$$

where

(iii) la norme ASTM applicable au type de combustible,

(iv) en l'absence d'une norme ASTM, toute méthode applicable qui est reconnue à l'échelle internationale,

c) dans le cas des combustibles solides, sur la même base sèche ou humide que celle qui a été choisie pour déterminer la variable CC_M et :

(i) s'agissant de combustibles solides dérivés de déchets, conformément à la norme ASTM E777-08 intitulée *Standard Test Method for Carbon and Hydrogen in the Analysis Sample of Refuse-Derived Fuel*,

(ii) s'agissant d'autres combustibles solides, conformément à la norme ou méthode ci-après qui permet d'en mesurer le contenu en carbone :

(A) la norme ASTM applicable au type de combustible,

(B) en l'absence d'une telle norme, toute méthode applicable qui est reconnue à l'échelle internationale;

i la i^e période d'échantillonnage visée à l'article 21 où « i » est un chiffre de 1 à n, « n » étant le nombre de ces périodes d'échantillonnage;

Q_i le volume ou la masse, selon le cas, du combustible brûlé au cours de la i^e période d'échantillonnage, exprimé :

a) exprimé en m^3 et mesuré dans des conditions normales, pour les combustibles gazeux,

b) exprimé en kL, pour les combustibles liquides,

c) exprimé en tonnes, pour les combustibles solides, sur la même base sèche ou humide que celle qui a été choisie pour déterminer la variable CC_M.

Énergie thermique utile

Émissions — énergie thermique utile (E_{th})

15 La quantité des émissions de CO_2 par un groupe qui est attribuable à la production d'énergie thermique utile est déterminée conformément à la formule suivante :

$$H_{pnette} \times b_{EI}$$

où :

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H_{pnet} is the net useful thermal energy, expressed in GJ, determined by the formula:

$$\sum_{t=1}^{x}\left[\sum_{i=1}^{n}\left\{h_{out\_i}\times M_{out\_i}\right\}-\sum_{j=1}^{m}\left\{h_{in\_j}\times M_{in\_j}\right\}\right]_t$$

where

t is the tth hour, where "t" goes from 1 to x and where x is the total number of hours during which the unit produced useful thermal energy in the calendar year,

i is the ith heat stream exiting the unit, where "i" goes from 1 to n and where n is the total number of heat streams exiting the unit,

h_{out_i} is the average specific enthalpy of the ith heat stream exiting the unit, expressed in GJ/tonne, during period "t" and must be based on the measurement of the temperature and pressure of that heat stream and determined using a continuous measuring device,

M_{out_i} is the mass flow of the ith heat stream exiting the unit, expressed in tonnes, during period "t", determined using a continuous measuring device,

j is the jth heat stream, other than condensate return, entering the unit, where "j" goes from 1 to m and where m is the total number of heat streams entering the unit,

h_{in_j} is the average specific enthalpy of the jth heat stream, other than condensate return, entering the unit, expressed in GJ/tonne, during period "t" and must be based on the measurement of the temperature and pressure of that heat stream and determined using a continuous measuring device,

M_{in_j} is the mass flow of the jth heat stream, other than condensate return, entering the unit, expressed in tonnes, during period "t" and determined using a continuous measuring device; and

b_{EI} is the emission intensity of a reference boiler, set to 0.0556 tonnes of CO_2/GJ.

H_{pnette} représente la quantité d'énergie thermique utile nette, exprimée en GJ, déterminée conformément à la formule suivante :

$$\sum_{t=1}^{x}\left[\sum_{i=1}^{n}\left\{h_{sort\_i}\times M_{sort\_i}\right\}-\sum_{j=1}^{m}\left\{h_{intr\_j}\times M_{intr\_j}\right\}\right]_t$$

où :

t représente la t^{e} heure, où « t » est un chiffre de 1 à x, « x » étant le nombre total d'heures au cours desquelles le groupe a produit de l'énergie thermique utile au cours de l'année civile,

i le i^{e} flux calorifique sortant du groupe, où « i » est un chiffre de 1 à n, « n » étant le nombre total de flux calorifiques sortants,

h_{sort_i} l'enthalpie spécifique moyenne au cours de la période « t » du i^{e} flux calorifique sortant du groupe, exprimée en GJ/tonne et déterminée au moyen d'un instrument de mesure en continu selon les mesures de la température et de la pression de ce i^{e} flux calorifique,

M_{sort_i} le débit massique au cours de la période « t » du i^{e} flux calorifique sortant du groupe, exprimé en tonnes et déterminé au moyen d'un instrument de mesure en continu,

j le j^{e} flux calorifique, autre que le flux de condensat de retour, entrant dans le groupe, où « j » est un chiffre de 1 à m, « m » étant le nombre total de flux calorifiques entrants,

h_{intr_j} l'enthalpie spécifique moyenne au cours de la période « t » du j^{e} flux calorifique, autre que le flux de condensat de retour, entrant dans le groupe, exprimée en GJ/tonne et déterminée au moyen d'un instrument de mesure en continu selon les mesures de la température et de la pression de ce j^{e} flux calorifique,

M_{intr_j} le débit massique au cours de la période « t » du j^{e} flux calorifique, autre que le flux de condensat de retour, entrant dans le groupe, exprimé en tonnes et déterminé au moyen d'un instrument de mesure en continu,

b_{EI} l'intensité des émissions d'une chaudière de référence, fixée à 0,0556 tonne CO_2/GJ.

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Carbon Capture and Storage

Emissions captured and stored (E_{ccs})

16 The quantity of CO_2 that is captured from the unit during the calendar year and stored in a storage project is determined by the formula

$$E_u \times (E_{cap} \div E_{in})$$

where

E_u is the value of E_u in subsection 8(1);

E_{cap} is the quantity of CO_2 emissions that is the portion of E_{in} that has been captured and subsequently stored, during the calendar year, in a storage project that meets the criteria set out in subsection 8(4), expressed in tonnes, determined by means of direct measuring devices that measure the flow of, and the concentration of CO_2 in, those emissions; and

E_{in} is the quantity of CO_2 emissions, expressed in tonnes, entering the carbon capture and storage system during the calendar year, determined using a CEMS, in accordance with Sections 7.1 to 7.7 of the Reference Method, that measures upstream of the carbon capture and storage system and that measures all emissions entering the carbon capture and storage system.

Hydrogen Fuel and Steam

Quantification of emissions (E_{ext})

17 (1) The quantity of CO_2 emitted from the production of the hydrogen fuel or steam used by the unit to generate electricity is determined by the formula

$$\sum_{k=1}^{n}\left(\left(\frac{E_k}{P_k}\right) \times Q_k\right)$$

where

E_k is the total annual CO_2 emissions that result from the total annual production of hydrogen fuel or from the total annual production of steam, expressed in tonnes, in the calendar year;

P_k is the total annual production of the hydrogen fuel, expressed in m^3 at standard conditions, or steam, expressed in GJ, in a calendar year, determined using a continuous measuring device;

Captage et de stockage de carbone

Émissions captées et stockées (E_{csc})

16 La quantité des émissions de CO_2 qui est captée d'un groupe et stockée dans le cadre d'un projet de stockage au cours d'une année civile est déterminée conformément à la formule suivante :

$$E_g \times (E_{cap} \div E_{in})$$

où :

E_g représente la valeur de la variable E_g visée au paragraphe 8(1);

E_{cap} la quantité d'émissions de CO_2 qui est la portion de E_{in} qui est captée et subséquemment stockée, au cours de l'année civile, par un projet de stockage qui respecte les critères prévus au paragraphe 8(4), exprimée en tonnes et déterminée à l'aide d'une mesure directe de leur débit et de leur concentration en CO_2;

E_{in} la quantité d'émissions de CO_2, exprimée en tonnes, entrant dans le système de captage et de stockage de carbone, au cours de l'année civile, déterminée à l'aide d'un SMECE, conformément aux sections 7.1 à 7.7 de la méthode de référence, situé en amont du système de captage et de stockage de carbone et mesurant toutes les émissions entrant dans ce système .

Hydrogène et vapeur

Quantification des émissions (E_{ext})

17 (1) La quantité des émissions de CO_2 provenant de la production d'hydrogène ou de vapeur utilisé par le groupe pour produire de l'électricité est déterminée conformément à la formule suivante :

$$\sum_{k=1}^{n}\left(\left(\frac{E_k}{P_k}\right) \times Q_k\right)$$

où :

E_k représente la quantité totale des émissions annuelles de CO_2 provenant de la production annuelle totale d'hydrogène ou de la production annuelle totale de vapeur, exprimée en tonnes, au cours d'une année civile;

P_k la production annuelle totale d'hydrogène, exprimée en m^3 et mesurée dans des conditions normales, ou

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Q_k is the quantity of hydrogen, expressed in m^3 at standard conditions, or purchased or transferred steam, expressed in GJ, used by the unit to generate electricity, during the calendar year, determined using a continuous measuring device; and

k is the kth stream of hydrogen or steam, with "k" going from 1 to n, where n is the number of streams of hydrogen or steam that are used by the unit during the calendar year.

Quantification of E_k and P_k

(2) The responsible person must, if possible, obtain the quantity of E_k and P_k from the supplier of the hydrogen fuel or steam, quantified in accordance with section 10 of the GHGRP with respect to hydrogen production and with section 7 of the GHGRP with respect to electricity and heat production.

Variable R_{CO2}

(3) For the purposes of subsection (2), the description of the element R_{CO2} in Equation 10-2 of the GHGRP must be read as "CO_2 captured and permanently stored in a storage project that meets the criteria set out in paragraphs 8(4)(a) and (b) of these Regulations".

Default value

(4) Despite subsection (2), the responsible person must replace the ratio $E_k \div P_k$ in the formula set out in subsection (1), with 0.08 tonnes of CO_2/GJ for both hydrogen and steam if

(a) the production of hydrogen fuel does not occur at the facility at which the unit is located or the steam is purchased or transferred to the facility at which the unit is located; and

(b) the responsible person is not able to get the information required to determine E_k or P_k from the supplier of the hydrogen fuel or steam.

Quantity of Electricity

Quantity of electricity

18 (1) The quantity of electricity generated by the unit is determined by the formula

$$G_{gross} - G_{ec}$$

de vapeur, exprimée en GJ, au cours de l'année civile, déterminée à l'aide d'un dispositif de mesure en continu;

Q_k la quantité d'hydrogène, exprimée en m^3 et mesurée dans des conditions normales, ou de vapeur achetée ou transférée, exprimée en GJ, utilisée par le groupe pour produire de l'électricité, au cours de l'année civile, déterminée à l'aide d'un dispositif de mesure en continu;

k le k^e flux d'hydrogène ou de vapeur, où « k » est un nombre de 1 à n, « n » étant le nombre de flux d'hydrogène ou de vapeur utilisés par le groupe, au cours de l'année civile.

Quantification des variables E_k et P_k

(2) La personne responsable obtient, dans la mesure du possible, les valeurs E_k et de P_k du fournisseur d'hydrogène ou de vapeur, lesquelles sont quantifiées conformément à la section 10 de la méthode d'ECCC en ce qui concerne l'hydrogène et conformément à la section 7 de la méthode d'ECCC en ce qui concerne la production d'électricité et de chaleur.

Variable R_{CO2}

(3) Pour l'application du paragraphe (2), la description de la variable R_{CO2} dans l'équation 10–2 de la méthode d'ECCC s'entend de « CO_2 capté et stocké dans un projet de stockage qui remplit les critères énumérés aux alinéas 8(4)a) et b) du présent règlement ».

Valeur par défaut

(4) Malgré le paragraphe (2), la personne responsable remplace le ratio $E_k \div P_k$ dans la formule prévue au paragraphe (1) par la valeur par défaut 0,08 tonne CO_2/GJ pour l'hydrogène et pour la vapeur si :

a) d'une part, la production d'hydrogène n'a pas lieu dans l'installation où se trouve le groupe ou la vapeur est achetée ou transférée à l'installation où se trouve le groupe;

b) d'autre part, la personne responsable n'est pas en mesure d'obtenir les renseignements requis pour déterminer les variables E_k et P_k auprès du fournisseur d'hydrogène ou de vapeur.

Quantité d'électricité

Quantité d'électricité

18 (1) La quantité d'électricité produite par un groupe est calculée conformément à la formule suivante :

$$G_{brute} - G_{su}$$

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where

G_{gross} is the gross quantity of electricity generated by the unit in the calendar year, expressed in GWh, measured at the electrical terminals of the generators of the unit using a meter that has received an approval referred to in subsection 9(4) of the *Electricity and Gas Inspection Act*; and

G_{ec} is the gross quantity of electricity generated by the unit during any period during the calendar year for which the Minister has issued an exemption under section 19 or an extension under section 20, expressed in GWh, measured at the electrical terminals of the generators of the unit using a meter that has received an approval referred to in subsection 9(4) of the *Electricity and Gas Inspection Act*.

Meter specifications

(2) The meters referred to in subsection (1) must be installed and used in accordance with the most current electricity specification relating to design, composition, construction and performance of the class, type or design of that meter referred to in subsection 12(1) of the *Electricity and Gas Inspection Regulations*, published on the Measurement Canada website as an electricity specification.

Emergency Circumstances

Application for exemption

19 (1) A responsible person, under an emergency circumstance described in subsection (2), may apply to the Minister for an exemption from subsections 6(1) to (3) in respect of a unit if, as a result of the emergency, the operator of the electricity system in the province in which the unit is located or an official of that province responsible for ensuring and supervising the electricity supply orders the responsible person to produce electricity to avoid a threat to the supply or to restore that supply.

Definition of emergency circumstance

(2) An emergency circumstance is a circumstance

(a) that arises due to an extraordinary, unforeseen and irresistible event; or

(b) under which one or more of the measures referred to in paragraph 1(a) of the *Regulations Prescribing*

où :

G_{brute} représente la quantité brute d'électricité produite par le groupe au cours de l'année civile, exprimée en GWh et mesurée aux bornes électriques des générateurs du groupe à l'aide d'un compteur à l'égard duquel l'approbation visée au paragraphe 9(4) de la *Loi sur l'inspection de l'électricité et du gaz* a été délivrée;

G_{su} la quantité brute d'électricité produite par le groupe au cours de toute période pendant l'année civile qui est visée par une exemption accordée par le ministre en application de l'article 19 ou prolongée par celui-ci en application de l'article 20, exprimée en GWh et mesurée aux bornes électriques des générateurs du groupe à l'aide d'un compteur à l'égard duquel l'approbation visée au paragraphe 9(4) de la *Loi sur l'inspection de l'électricité et du gaz* a été délivrée.

Normes relatives aux compteurs

(2) Les compteurs visés au paragraphe (1) sont installés et utilisés de manière à ce que soient respectées les normes les plus récentes relatives à la conception, à la composition, à la construction et au fonctionnement auxquelles un compteur ou une catégorie, un type ou un modèle de compteur doit se conformer aux termes du paragraphe 12(1) du *Règlement sur l'inspection de l'électricité et du gaz*, publiées sur le site Internet de Mesures Canada à titre de norme en matière d'électricité.

Situations d'urgence

Demande d'exemption

19 (1) La personne responsable peut, dans une situation d'urgence visée au paragraphe (2), présenter au ministre une demande d'exemption de l'application des paragraphes 6(1) à (3) à l'égard d'un groupe si, en raison de la situation d'urgence, l'exploitant du réseau électrique de la province où le groupe est situé ou un responsable de cette province chargé d'assurer et de surveiller l'approvisionnement en électricité lui ordonne de produire de l'électricité afin de prévenir un danger pour l'approvisionnement en électricité ou de rétablir cet approvisionnement.

Définition de situation d'urgence

(2) Est une situation d'urgence la situation qui résulte de l'une des circonstances suivantes :

a) le cas de force majeure;

b) la circonstance dans laquelle au moins une des mesures visées à l'alinéa 1a) du *Règlement prévoyant les*

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Circumstances for Granting Waivers Pursuant to Section 147 of the Act has been made or issued in the province where the unit is located.

Application — deadline and content

(3) The application for the exemption must be provided to the Minister within 15 days after the day on which the emergency circumstance arises. The application must include the information referred to in section 1 and paragraphs 2(a) to (d) of Schedule 1 or the unit's registration number, the date on which the emergency circumstance arose and information, along with supporting documents, to demonstrate that the conditions set out in subsection (1) of this section are met.

Minister's decision

(4) If the Minister is satisfied that the conditions set out in subsection (1) are met, the Minister must, within 30 days after the day on which the application is received, grant the exemption.

Duration of exemption

(5) The exemption becomes effective on the day on which the emergency circumstance arises and ceases to have effect on the earliest of

(a) the 90th day after that day,

(b) the day specified by the Minister,

(c) the day on which the circumstance referred to in paragraph (2)(a) ceases to cause a disruption, or a significant risk of disruption, to the electricity supply in the province where the unit is located, and

(d) the day on which the measure, if any, referred to in paragraph (2)(b) ceases to have effect.

Application for extension of exemption

20 (1) If the conditions set out in subsection 19(1) will continue to exist after the day on which the exemption granted under paragraph 19(4) is to cease to have effect, the responsible person may, before that day, apply to the Minister for an extension of the exemption.

Contents of application

(2) The application must include

(a) the unit's registration number, assigned by the Minister, if applicable;

(b) the day on which the emergency circumstance began; and

circonstances donnant ouverture à une exemption en vertu de l'article 147 de la Loi a été prise au préalable dans la province où le groupe est situé.

Délai et contenu de la demande

(3) La demande d'exemption est présentée au ministre dans les quinze jours suivant la date du début de la situation d'urgence. Elle comporte les renseignements visés à l'article 1 et aux alinéas 2a) à d) de l'annexe 1 ou le numéro d'enregistrement du groupe, la date à laquelle la situation d'urgence a débuté et les renseignements établissant, documents à l'appui, que les conditions prévues au paragraphe (1) du présent article sont réunies.

Décision du ministre

(4) Le ministre fait droit à la demande d'exemption dans les trente jours suivant la date de réception de la demande s'il est convaincu que les conditions visées au paragraphe (1) sont réunies.

Durée de l'exemption

(5) L'exemption est valide à compter de la date du début de la situation d'urgence jusqu'à la première des dates ci-après à survenir :

a) la date à laquelle tombe le quatre-vingt-dixième jour suivant cette date;

b) la date fixée par le ministre;

c) la date à laquelle la circonstance visée à l'alinéa (2)a) cesse d'entraîner une interruption ou un risque important d'interruption de l'approvisionnement en électricité dans la province où le groupe est situé;

d) la date à laquelle la mesure visée à l'alinéa (2)b) cesse de s'appliquer.

Demande de prolongation de l'exemption

20 (1) Si les conditions prévues au paragraphe 19(1) persistent au-delà de la durée de l'exemption accordée au titre du paragraphe 19(4), la personne responsable peut, tant que l'exemption est valide, présenter au ministre une demande de prolongation de celle-ci.

Contenu de la demande

(2) La demande de prolongation comporte :

a) le cas échéant, le numéro d'enregistrement que lui a attribué le ministre;

b) la date du début de la situation d'urgence;

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(c) information, along with supporting documents that demonstrate that the conditions set out in subsection 19(1) will continue to exist after the day on which the exemption is to cease to have effect.

Minister's decision

(3) If the Minister is satisfied that the condition referred to in paragraph (2)(c) has been demonstrated, the Minister must grant the extension within 15 days after the day on which the application is received.

Duration of extension

(4) The extension ceases to have effect on the earliest of

(a) the 90th day after the day on which the application for the extension was made,

(b) the day specified by the Minister, and

(c) the day referred to in paragraph 19(5)(c).

Sampling and Missing Data

Sampling

21 (1) The determination of the value of the elements referred to in a formula in section 14 must be based on fuel samples taken in accordance with this section.

Carbon content provided by the supplier

(2) If the supplier of the fuel has provided the carbon content of the fuel and that carbon content has been determined in accordance with subsection 14(2), using the applicable sampling period and minimum sampling frequency set out in subsection (3), the responsible person may use that information rather than taking samples in accordance with subsection (3).

Frequency

(3) Each fuel sample must be taken at a time and location in the fuel handling system of the facility that provides the following representative samples of the fuel combusted at the applicable minimum frequency:

(a) for natural gas, during each sampling period consisting of each year that the unit generates electricity or produces useful thermal energy, two samples taken that year, with each of those samples being taken at least four months after any previous sample has been

c) les renseignements établissant, documents à l'appui, que les conditions prévues au paragraphe 19(1) persistent au-delà de la durée de l'exemption accordée.

Décision du ministre

(3) Le ministre fait droit à la demande de prolongation dans les quinze jours suivant la date de réception de la demande s'il est convaincu que la condition prévue à l'alinéa (2)c) a été établie.

Durée de la prolongation

(4) La prolongation est valide jusqu'à la première des dates ci-après à survenir :

a) la date tombant le quatre-vingt-dixième jour suivant la date à laquelle la demande de prolongation a été présentée;

b) la date fixée par le ministre;

c) la date visée à l'alinéa 19(5)c).

Échantillonnage et données manquantes

Échantillonnage

21 (1) La valeur des variables des formules visées à l'article 14 est déterminée à partir d'échantillons de combustible prélevés conformément au présent article.

Contenu en carbone fourni par le fournisseur

(2) Si le fournisseur du combustible lui a fourni le contenu en carbone du combustible et que ce contenu en carbone a été déterminé conformément au paragraphe 14(2) en utilisant la période d'échantillonnage et la fréquence d'échantillonnage minimale applicables précisées au paragraphe (3), la personne responsable peut utiliser cette information au lieu de prélever des échantillons conformément à ce paragraphe.

Fréquence

(3) Chaque prélèvement est effectué à un moment et à un point du système de manutention du combustible de l'installation permettant de fournir les échantillons représentatifs ci-après du combustible brûlé, à la fréquence minimale applicable :

a) s'agissant de gaz naturel, durant chaque période d'échantillonnage correspondant à chaque année au cours de laquelle le groupe produit de l'électricité ou

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taken, in accordance with whichever of the following standard that applies:

(i) ASTM D4057-12, entitled *Standard Practice for Manual Sampling of Petroleum and Petroleum Products*,

(ii) ASTM D4177-16e1, entitled *Standard Practice for Automatic Sampling of Petroleum and Petroleum Products*,

(iii) ASTM D5287-08(2015), entitled *Standard Practice for Automatic Sampling of Gaseous Fuels*, and

(iv) ASTM F307-13, entitled *Standard Practice for Sampling Pressurized Gas for Gas Analysis*;

(b) for refinery gas, during each sampling period consisting of each day that the unit generates electricity or produces useful thermal energy, one sample per day that is taken at least six hours after any previous sample has been taken, in accordance with any applicable standard referred to in paragraph (a);

(c) for a type of liquid fuel or of a gaseous fuel other than refinery gas and natural gas, during each sampling period consisting of each month that the unit generates electricity or produces useful thermal energy, one sample per month that is taken at least two weeks after any previous sample has been taken, in accordance with any of the standards referred to in paragraph (a); and

(d) for a solid fuel, one composite sample per month that consists of sub-samples, each having the same mass, that are taken from the fuel that is fed for combustion during each week that begins in that month and during which the unit generates electricity or produces useful thermal energy, and after all fuel treatment operations have been carried out but before any mixing of the fuel from which the sub-sample is taken with other fuels, and at least 72 hours after any previous sub-sample has been taken.

Additional samples

(4) Despite subsection (3), if the responsible person takes more samples or composite samples, as the case may be, than the minimum required and a determination is made on the carbon content of any of those samples or composite samples, using a method set out for CC_i in subsection 14(2) for that fuel type, the results of those determinations must be included in the determination of CC_A set out in subsection 14(2).

de l'énergie thermique utile, deux échantillons prélevés au cours de cette année, à au moins quatre mois d'intervalle, selon la norme applicable suivante :

(i) la norme ASTM D4057-12 intitulée *Standard Practice for Manual Sampling of Petroleum and Petroleum Products*,

(ii) la norme ASTM D4177-16e1 intitulée *Standard Practice for Automatic Sampling of Petroleum and Petroleum Products*,

(iii) la norme ASTM D5287-08(2015) intitulée *Standard Practice for Automatic Sampling of Gaseous Fuels*,

(iv) la norme ASTM F307-13 intitulée *Standard Practice for Sampling Pressurized Gas For Gas Analysis*;

b) s'agissant de gaz de raffinerie, durant chaque période d'échantillonnage correspondant à chaque journée au cours de laquelle le groupe produit de l'électricité ou de l'énergie thermique utile, un échantillon de gaz de raffinerie par journée, prélevé au moins six heures après l'échantillon précédant, conformément à l'une des normes applicables visées à l'alinéa a);

c) s'agissant d'un type de combustible liquide ou gazeux autre que du gaz de raffinerie ou du gaz naturel, durant chaque période d'échantillonnage correspondant à chaque mois au cours duquel le groupe produit de l'électricité ou de l'énergie thermique utile, un échantillon de combustible par mois, prélevé à au moins deux semaines d'intervalle, conformément à l'une des normes visées à l'alinéa a);

d) s'agissant d'un combustible solide, un échantillon composite par mois établi à partir de sous-échantillons de même masse du combustible ayant servi à la combustion prélevés chaque semaine au cours de laquelle le groupe produit de l'électricité ou de l'énergie thermique utile et qui commence au cours du mois, après tout traitement du combustible, mais avant que celui-ci ne soit mélangé à d'autres combustibles, et à au moins soixante-douze heures d'intervalle.

Échantillons additionnels

(4) Malgré le paragraphe (3), si le nombre d'échantillons ou d'échantillons composites, selon le cas, prélevés dépasse le nombre minimal requis et qu'une détermination du contenu en carbone de ceux-ci est faite conformément à la formule prévue au paragraphe 14(2) pour déterminer la valeur de la variable CC_i pour le type de combustible en cause, la personne responsable tient compte des résultats

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Missing data

22 (1) If, for any reason beyond the responsible person's control, any element of any formula in the Regulations cannot be determined because data required to determine it is missing for a given period in a calendar year, replacement data for that given period must be used to determine that value.

Replacement data — CEMS

(2) If a CEMS is used to determine the value of an element of a formula set out in sections 9 to 11 but data is missing for a given period, the replacement data must be obtained in accordance with Section 3.5.2 of the Reference Method.

Replacement data — non-CEMS

(3) If data, other than data referred to in subsection (2), required to determine the value of any element of a formula in these Regulations is missing for a given period, the replacement data is to be the average of the available data for that element during the equivalent period prior to and, if the data is available, subsequent to that given period. However, if no data is available for that element for the equivalent period prior to that given period, the replacement data to be used is the value determined for that element during the equivalent period subsequent to the given period.

Replacement data — maximum days

(4) During a calendar year, there may be more than one given period, but replacement data may be used for a maximum of 28 days during the calendar year, distributed among any or all of those periods.

Accuracy of Data

Measuring devices — installation, maintenance and calibration

23 (1) A responsible person must install, maintain and calibrate a measuring device, other than a continuous emission monitoring system and a measuring device that is subject to the *Electricity and Gas Inspection Act*, that is used for the purposes of these Regulations in accordance with the manufacturer's instructions or any applicable generally recognized national or international industry standard.

de cette détermination pour déterminer la valeur de la variable CC_m prévue au paragraphe 14(2).

Données manquantes

22 (1) Si, pour une raison indépendante de la volonté de la personne responsable, il manque, pour une période donnée d'une année civile, des données pour déterminer une variable des formules prévues au présent règlement, des données de remplacement, établies pour cette période, sont utilisées à cette fin.

Variable déterminée à l'aide d'un SMECE

(2) Si un SMECE est utilisé pour déterminer une variable des formules prévues aux articles 9 à 11 et qu'il manque une donnée pour une période donnée, la donnée de remplacement est obtenue conformément à la section 3.5.2 de la méthode de référence.

Variable non déterminée à l'aide d'un SMECE

(3) Si des données, autres que celles visées au paragraphe (2), requises pour déterminer la valeur d'une variable d'une formule prévu au présent règlement sont manquantes pour une période donnée, la donnée de remplacement est la moyenne des données disponibles pour cette variable pour la période équivalente précédant la période en cause et, si les données sont disponibles, pour la période équivalente qui la suit. Toutefois, si aucune donnée n'est disponible pour cette variable pour la période équivalente précédant la période en cause, la donnée de remplacement est la valeur établie pour la variable pour la période équivalente qui suit cette période.

Données de remplacement — durée maximale

(4) Si une donnée n'est pas disponible au cours d'une ou plusieurs périodes données au cours de l'année civile en cause, une donnée de remplacement ne peut être fournie que pour un maximum de vingt-huit jours de cette année civile, répartis sur une ou plusieurs des périodes en cause.

Exactitude des données

Instruments de mesure — mise en place, entretien et étalonnage

23 (1) La personne responsable met en place, entretient et étalonne les instruments de mesure — autres que le système de mesure et d'enregistrement en continu des émissions et que tout instrument de mesure assujetti à la *Loi sur l'inspection de l'électricité et du gaz* — utilisés pour l'application du présent règlement conformément aux instructions du fabricant ou à une norme applicable généralement reconnue par l'industrie à l'échelle nationale ou internationale.

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Frequency of calibration

(2) The responsible person must calibrate each of the measuring devices at the following frequencies:

(a) at least once in every calendar year but at least five months after a previous calibration; or

(b) the minimum frequency recommended by the manufacturer.

Accuracy of measurements

(3) The responsible person must use measuring devices that enable measurements to be made with a degree of accuracy of ±5%.

Reporting

Annual reports

24 (1) Subject to subsection (3), beginning in the calendar year during which section 6 applies to the responsible person, that responsible person must submit an annual report with respect to the unit containing the information referred to in Schedule 2 for each calendar year the unit meets the criteria set out in section 3 of these Regulations.

June 1

(2) The responsible person must submit the annual report on or before June 1 of the calendar year that follows the calendar year that is the subject of the report.

Permanent cessation

(3) If a unit permanently ceases to generate electricity in a calendar year, the responsible person for the unit must submit to the Minister a notice, in writing, not later than 60 days after the day on which the unit ceases generating electricity, containing the information set out in Schedule 5. An annual report is not required to be submitted in respect of the calendar years following the calendar year in which the unit ceases generating electricity.

Change of information

25 If there is a change to any information submitted to the Minister in the registration report, the responsible person must notify the Minister of the change and provide the new information, in writing, not later than 60 days after the day on which the change is made.

Correcting error

26 A responsible person must, without delay, notify the Minister, in writing, of any error in the information in a

Fréquence de l'étalonnage

(2) La personne responsable étalonne chacun des instruments de mesure à l'une ou l'autre des fréquences suivantes :

a) au moins une fois par année civile et à au moins cinq mois d'intervalle;

b) la fréquence minimale recommandée par le fabricant.

Exactitude des mesures

(3) La personne responsable utilise des instruments de mesure qui permettent la prise des mesures selon un degré d'exactitude de ± 5 %.

Rapports

Rapports annuels

24 (1) Sous réserve du paragraphe (3), la personne responsable est tenue, à compter de la première année au cours de laquelle l'article 6 s'applique à elle, de transmettre au ministre un rapport annuel à l'égard du groupe comportant les renseignements énumérés à l'annexe 2 à l'égard de chaque année civile au cours de laquelle le groupe remplit les conditions prévues à l'article 3 du présent règlement.

1er juin

(2) La personne responsable transmet le rapport annuel au plus tard le 1er juin de l'année civile qui suit l'année civile faisant l'objet du rapport.

Cessation définitive

(3) Si le groupe cesse définitivement de produire de l'électricité au cours de l'année civile, la personne responsable transmet au ministre un avis écrit contenant les renseignements visés à l'annexe 5 au plus tard soixante jours après la date à laquelle le groupe cesse sa production. Il n'est pas nécessaire de transmettre un rapport annuel à l'égard des années civiles suivant celle au cours de laquelle le groupe cesse sa production.

Modification aux renseignements

25 La personne responsable avise par écrit le ministre de toute modification apportée aux renseignements qui lui ont été fournis dans le rapport d'enregistrement et lui fournit les renseignements corrigés dans les soixante jours suivant le jour de la modification.

Correction d'erreur

26 La personne responsable, sans délai, avise par écrit le ministre de toute erreur dans les renseignements fournis

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report submitted in accordance with these Regulations and provide the corrected information.

Signature and submission — electronic

27 (1) A report or notice that is required, or an application that is made, under these Regulations must be submitted electronically in the form specified by the Minister and must bear the electronic signature of the responsible person or their authorized official.

Paper report, notice and application

(2) If the Minister has not specified an electronic form or if the person is unable to submit the report, notice or application electronically in accordance with subsection (1) because of circumstances beyond the person's control, the report, notice or application must be sent on paper, in the form specified by the Minister, if applicable, and be signed by the responsible person or their authorized official.

Records

Record

28 (1) A responsible person must make a record containing the following documents and information:

(a) any notice, declaration, application, attestation, report or information submitted to the Minister under these Regulations, along with supporting documents;

(b) measurements and calculations used to determine the value of an element of any formula set out in sections 7, 8, 10, 11 and 13 to 18, as applicable, along with an indication of the standards or methods that were used to determine the value of the elements used in those formulas, along with supporting documents;

(c) an indication of the standards or methods referred to in the description of CC_i in subsection 14(1) for a sample of gaseous fuel, including a statement that indicates that a direct measuring device was used to determine that value;

(d) information demonstrating that an electricity meter referred to in section 18 complies with the requirements of the *Electricity and Gas Inspection Act* and the *Electricity and Gas Inspection Regulations*, including a certificate referred to in section 14 of that Act;

(e) the manufacturer's instructions for any measuring device used to determine any value or quantity in any section of these Regulations;

dans un rapport transmis en application du présent règlement et lui fournit les renseignements corrigés.

Transmission et signature électroniques

27 (1) Les rapports et avis requis par le présent règlement et les demandes faites aux termes de celui-ci sont transmis électroniquement en la forme précisée par le ministre et portent la signature électronique de la personne responsable ou son agent autorisé.

Rapports, avis et demandes sur support papier

(2) Si le ministre n'a pas précisé de forme électronique ou si, en raison de circonstances indépendantes de sa volonté, la personne qui transmet le rapport ou l'avis ou qui présente la demande n'est pas en mesure de le faire conformément au paragraphe (1), elle transmet le rapport ou l'avis ou présente la demande sur support papier, signé par la personne responsable ou son agent autorisé, en la forme précisée par le ministre, le cas échéant.

Dossier

Contenu du dossier

28 (1) La personne responsable constitue un dossier contenant les renseignements et documents suivants :

a) tout avis, attestation, déclaration, demande, rapport ou renseignement transmis au ministre en application du présent règlement, y compris les documents à l'appui;

b) le relevé des mesures et la description des calculs effectués pour déterminer la valeur d'une variable des formules visées aux articles 7, 8, 10, 11 et 13 à 18, selon le cas, ainsi que la mention des normes ou des méthodes utilisées pour déterminer la valeur des variables de ces formules et les documents à l'appui;

c) la mention des normes ou des méthodes visées dans la description de la variable CC_i au paragraphe 14(2) pour un échantillon gazeux qui ont été utilisées et l'indication qu'un instrument de mesure directe a été utilisé à cette fin;

d) les renseignements établissant que les compteurs électriques visés à l'article 18 répondent aux exigences de la *Loi sur l'inspection de l'électricité et du gaz* et du *Règlement sur l'inspection de l'électricité et du gaz*, y compris celle relative au certificat prévue à l'article 14 de cette loi;

e) les instructions du fabricant relatives à tout instrument de mesure utilisé pour déterminer toute valeur ou quantité aux termes du présent règlement;

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(f) information demonstrating that the requirements set out in section 23 are met;

(g) supporting documents that confirm the CEMS certification under subsection 12(2);

(h) any document, record or information referred to in Section 8 of the Reference Method, for each calendar year during which a responsible person used a CEMS;

(i) the results of the analysis of every sample taken in accordance with section 21, as well as the date that each sample was taken and an indication of the standards that were used to take representative samples of the fuel;

(j) if the supplier of hydrogen or steam has provided the quantity of E_k or P_k under subsection 17(2), the information provided by the supplier;

(k) if the supplier of fuel has provided the carbon content of that fuel under subsection 21(2), the information provided by the supplier;

(l) information demonstrating electricity generation capacity submitted in the registration report and each annual report; and

(m) if replacement data was used under section 22, information with respect to the reason replacement data was required, along with the replacement data that was used.

f) les renseignements établissant que les exigences prévues à l'article 23 sont respectées;

g) les documents à l'appui qui confirment l'homologation du SMECE aux termes du paragraphe 12(2);

h) à l'égard de chaque année civile au cours de laquelle la personne responsable utilise un SMECE, les renseignements et les documents visés à la section 8 de la méthode de référence;

i) le résultat d'analyse de chaque échantillon prélevé conformément à l'article 21, ainsi que la date du prélèvement de chaque échantillon et la mention des normes qui ont été utilisées pour prendre les échantillons représentatifs du combustible;

j) si les valeurs de E_k et de P_k sont obtenues du fournisseur d'hydrogène ou de vapeur au titre du paragraphe 17(2), les renseignements obtenus du fournisseur;

k) si le contenu en carbone du combustible est obtenu du fournisseur du combustible au titre du paragraphe 21(2), les renseignements obtenus du fournisseur;

l) les renseignements établissant la capacité de production d'électricité indiquée dans le rapport d'enregistrement et dans chaque rapport annuel;

m) si des données de remplacement ont été utilisées en application de l'article 22, les renseignements établissant la raison pour laquelle les données étaient nécessaires ainsi que les données elles-mêmes.

Time limit

(2) The records must be made as soon as feasible but not later than 30 days after the day on which the information and documents to be included in it become available.

Délai

(2) Le dossier est constitué dès que possible, mais au plus tard trente jours après la date à laquelle les renseignements et documents devant y être consignés deviennent accessibles.

Retention of records, reports and notices

29 (1) A responsible person that is required under these Regulations to make a record or send a report or notice must keep the record or a copy of the report or notice, along with the supporting documents

(a) until the responsible person has submitted a notice of permanent cessation under subsection 24(3), with respect to documentation set out in Schedule 1; or

(b) for a period of seven years after the later of when the record is made or a report or notice is submitted to the Minister.

Conservation des dossiers, rapports et avis

29 (1) La personne responsable tenue, en application du présent règlement, de constituer un dossier ou de transmettre un rapport ou un avis conserve le dossier ou une copie du rapport ou de l'avis, ainsi que les documents à l'appui :

a) dans le cas des documents concernant les éléments énumérés à l'annexe 1, jusqu'à ce que la personne responsable transmette un avis de cessation définitive de production conformément au paragraphe 24(3);

b) dans les autres cas, pendant au moins sept ans après avoir constitué le dossier ou avoir transmis le rapport ou l'avis au ministre.

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Location of records

(2) A record or copy must be kept at the responsible person's principal place of business in Canada or at any other place in Canada where it can be inspected. If the record or copy is kept at any of those other places, the responsible person must provide the Minister with a civic address of that other place.

Relocation of records

(3) If the records are moved, the responsible person must notify the Minister, in writing, of the civic address in Canada of the new location within 30 days after the day of the move.

Language of Documents

Language of documents

30 All documents required by these Regulations must be in English or French, or be accompanied by a translation in English or French and an affidavit of the translator attesting to the accuracy of the translation.

Consequential Amendment to the Regulations Designating Regulatory Provisions for Purposes of Enforcement (Canadian Environmental Protection Act, 1999)

31 The schedule to the *Regulations Designating Regulatory Provisions for Purposes of Enforcement (Canadian Environmental Protection Act, 1999)*[1] is amended by adding the following in numerical order:

Item	Column 1 Regulations	Column 2 Provisions
42	*Clean Electricity Regulations*	(a) subsection 6(1) (b) subsection 6(2) (c) subsection 6(3)

[1] SOR/2012-134

Lieu de conservation des dossiers

(2) Le dossier ou la copie de celui-ci sont conservés à l'établissement principal de la personne responsable au Canada ou en tout autre lieu au Canada où ils peuvent être examinés. Dans ce dernier cas, la personne responsable informe le ministre de l'adresse municipale du lieu.

Changement de lieu de conservation

(3) Si le lieu de conservation du dossier change, la personne responsable avise le ministre par écrit de l'adresse municipale du nouveau lieu dans les trente jours suivant la date du changement.

Langue des documents

Langue des documents

30 Les documents exigés par le présent règlement sont rédigés en français ou en anglais ou sont accompagnés d'une traduction française ou anglaise et d'une déclaration sous serment du traducteur qui en atteste la fidélité.

Modification connexe au Règlement sur les dispositions réglementaires désignées aux fins de contrôle d'application — Loi canadienne sur la protection de l'environnement (1999)

31 L'annexe du *Règlement sur les dispositions réglementaires désignées aux fins de contrôle d'application — Loi canadienne sur la protection de l'environnement (1999)*[1] est modifiée par adjonction, selon l'ordre numérique, de ce qui suit :

Article	Colonne 1 Règlement	Colonne 2 Dispositions
42	*Règlement sur l'électricité propre*	a) paragraphe 6(1) b) paragraphe 6(2) c) paragraphe 6(3)

[1] DORS/2012-134

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Repeals

32 The *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*[2] is repealed.

33 The *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*[3] is repealed.

Coming into Force

January 1, 2025

34 (1) These Regulations, except sections 32 and 33, come into force on January 1, 2025.

January 1, 2035

(2) Section 32 comes into force on January 1, 2035.

January 1, 2045

(3) Section 33 comes into force on January 1, 2045.

Abrogations

32 Le *Règlement sur la réduction des émissions de dioxyde de carbone — secteur de l'électricité thermique au charbon*[2] est abrogé.

33 Le *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel*[3] est abrogé.

Entrée en vigueur

1er janvier 2025

34 (1) Le présent règlement, sauf les articles 32 et 33, entre en vigueur le 1er janvier 2025.

1er janvier 2035

(2) L'article 32 entre en vigueur le 1er janvier 2035.

1er janvier 2045

(3) L'article 33 entre en vigueur le 1er janvier 2045.

[2] SOR/2012-167
[3] SOR/2018-261

[2] DORS/2012-167
[3] DORS/2018-261

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SCHEDULE 1

(Subsection 4(1), paragraph 4(2)(a), subsection 19(3), and paragraph 29(1)(a))

Registration Report — Information Required

1 The following information respecting the responsible person:

(a) an indication of whether they are the owner or operator of the unit and their name and civic address;

(b) the name, title, civic and postal addresses, telephone number and, if any, email address and fax number of their authorized official; and

(c) the name, title, civic and postal addresses, telephone number and, if any, email address and fax number of a contact person, if different from the authorized official.

2 The following information respecting the unit:

(a) for each responsible person for the unit, other than the responsible person referred to in paragraph 1(a), if any,

(i) their name and civic address,

(ii) an indication of whether they are an owner or operator, and

(iii) in the case of an owner, their percentage of ownership interest;

(b) its name and civic address, if any;

(c) if applicable, its National Pollutant Release Inventory identification number assigned by the Minister for the purpose of section 48 of the *Canadian Environmental Protection Act, 1999*;

(d) the year, determined in accordance with section 6(4) of these Regulations, in which it must meet the intensity limit;

(e) its commissioning date;

(f) the date each piece of equipment that comprises it started operating;

(g) the date on which the carbon capture and storage system equipment started operating, if applicable;

(h) its electricity generation capacity;

(i) its registration number, if any, assigned by the Minister under subsection 4(2) of the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*;

ANNEXE 1

(paragraphe 4(1), alinéa 4(2)a), paragraphe 19(3) et alinéa 29(1)a))

Rapport d'enregistrement — renseignements à fournir

1 Renseignements sur la personne responsable :

a) une mention portant qu'elle est le propriétaire ou l'exploitant du groupe, ainsi que ses nom et adresse municipale;

b) les nom, titre, adresses municipale et postale, numéro de téléphone et, le cas échéant, numéro de télécopieur et adresse électronique de son agent autorisé;

c) les nom, titre, adresses municipale et postale, numéro de téléphone et, le cas échéant, numéro de télécopieur et adresse électronique d'une personne-ressource, si celle-ci n'est pas l'agent autorisé.

2 Renseignements sur le groupe :

a) le cas échéant, à l'égard de chaque personne responsable du groupe autre que celle qui est mentionnée à l'alinéa 1a) :

(i) ses nom et adresse municipale,

(ii) une mention portant qu'elle est le propriétaire ou l'exploitant,

(iii) dans le cas où elle est le propriétaire, le pourcentage du titre de participation dans ce groupe;

b) ses nom et adresse municipale, le cas échéant;

c) le cas échéant, le numéro d'identification que lui a attribué le ministre pour les besoins de l'inventaire national des rejets polluants établi en application de l'article 48 de la *Loi canadienne sur la protection de l'environnement (1999)*;

d) l'année déterminée en application du paragraphe 6(4) du présent règlement au cours de laquelle il est tenu de respecter la limite d'intensité d'émissions;

e) la date de sa mise en service;

f) pour chaque pièce d'équipement du groupe, la date à laquelle elle a commencé à fonctionner;

g) la date à laquelle l'équipement du système de captage et de stockage de carbone a commencé à fonctionner, s'il y a lieu;

h) sa capacité de production d'électricité;

i) le cas échéant, le numéro d'enregistrement que lui a attribué le ministre en vertu du paragraphe 4(2) du

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(j) the unit's registration number, if any, assigned by the Minister under subsection 21(4) of the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*;

(k) a process diagram of the unit that indicates, if applicable,

(i) major equipment, including boilers, combustion engines, duct burners and other combustion devices, heat recovery systems, steam turbines, generators and emission control devices and carbon capture and storage system equipment,

(ii) how the equipment referred to in subparagraph (i) is physically connected and operates together,

(iii) the unit boundaries used to identify the unit,

(iv) the electric flows crossing the unit boundaries, and

(v) if applicable, the heat streams crossing the unit boundaries and their average temperature, pressure and hourly mass flow rate; and

(l) if the unit contains a combustion engine, boiler or steam turbine that was previously contained in another unit registered under these Regulations,

(i) the registration number of the previous unit,

(ii) the electricity generation capacity of the combustion engine, that is part of the combustion equipment, or steam turbine, as applicable, and

(iii) the date on which the combustion engine, boiler or steam turbine started operating in the unit that is the subject of the report.

Règlement sur la réduction des émissions de dioxyde de carbone provenant de la production d'électricité au charbon;

j) le cas échéant, le numéro d'enregistrement du groupe attribué par le ministre en application du paragraphe 21(4) du *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel*;

k) un schéma de procédé illustrant, pour le groupe, s'il y a lieu :

(i) l'équipement principal, notamment les chaudières, moteurs à combustion, brûleurs de conduit ou autres dispositifs de combustion, systèmes de récupération de la chaleur, turbines à vapeur, générateurs ou dispositifs de contrôle des émissions,

(ii) comment tout équipement visé au sous-alinéa (i) est physiquement raccordé et fonctionne ensemble,

(iii) le périmètre utilisé pour identifier le groupe,

(iv) les flux électriques qui franchissent le périmètre du groupe,

(v) le cas échéant, les flux calorifiques qui franchissent le périmètre du groupe et leur température, leur pression et leur débit massique horaire moyens;

l) s'il comprend un moteur à combustion, une chaudière ou une turbine à vapeur qui étaient compris dans un groupe qui était déjà enregistré aux termes du présent règlement :

(i) le numéro d'enregistrement du groupe déjà enregistré,

(ii) la capacité de production d'électricité de tout moteur à combustion compris dans l'équipement de combustion, ou de toute turbine à vapeur, selon le cas,

(iii) la date à laquelle le moteur à combustion, la chaudière ou la turbine à vapeur du groupe qui fait l'objet du rapport a commencé à fonctionner.

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SCHEDULE 2

(Subsections 5(4) and 24(1))

Annual Report — Information Required

1 The unit's registration number, assigned by the Minister under subsection 4(3) of these Regulations.

2 The following information for the calendar year:

(a) the number of hours during which the unit produced electricity; and

(b) with respect to a unit for which the Minister has issued an exemption under section 19 or an extension under section 20 of these Regulations,

(i) the period for which the exemption or extension was issued,

(ii) the number of hours during the period referred to in subparagraph (i) during which the unit operated.

3 The following information respecting the emission intensity referred to in section 7 of these Regulations:

(a) the emission intensity for the unit, expressed in tonnes of CO_2 per GWh;

(b) in respect of the quantity of CO_2 emissions from the combustion of fuels in the unit (E_u), if that quantity is

(i) determined in accordance with section 9, 10 or 11 of these Regulations, the quantity determined in accordance with the applicable section, expressed in tonnes, and

(ii) determined in accordance with section 13 of these Regulations,

(A) the quantity determined in accordance with that section, expressed in tonnes,

(B) the quantity of CO_2 emissions attributable to the combustion of a fossil fuel for each fossil fuel type (E_i), determined in accordance with section 14 of these Regulations, expressed in tonnes, and

(C) the quantity of CO_2 emissions that is released from the sorbent (E_s), for each fossil fuel type, expressed in tonnes;

(c) for each type of fuel combusted in the unit

(i) the type, and if that type is biomass, an explanation of how that it meets the definition *biomass* in subsection 2(1) of these Regulations, and

ANNEXE 2

(paragraphes 5(4) et 24(1))

Rapport annuel — renseignements à fournir

1 Le numéro d'enregistrement du groupe attribué par le ministre en application du paragraphe 4(3) du présent règlement.

2 Renseignements à l'égard des éléments ci-après pour l'année civile :

a) le nombre d'heures pendant lesquelles le groupe a produit de l'électricité;

b) dans le cas d'un groupe visé par une exemption accordée en application de l'article 19 du présent règlement ou prolongée en application de l'article 20 de celui-ci :

(i) la période à l'égard de laquelle l'exemption a été accordée ou prolongée,

(ii) le nombre d'heures au cours de la période visée au sous-alinéa (i) durant lesquelles le groupe a fonctionné.

3 Renseignements sur l'intensité des émissions visée à l'article 7 du présent règlement :

a) l'intensité des émissions provenant du groupe, exprimée en tonnes de CO_2 par GWh;

b) à l'égard de la quantité d'émissions de CO_2 provenant de la combustion de combustibles par le groupe (E_g) :

(i) si elle est déterminée conformément aux articles 9, 10 ou 11 du présent règlement, la quantité déterminée conformément à l'article applicable, exprimée en tonnes,

(ii) si elle est déterminée conformément à l'article 13 du présent règlement :

(A) la quantité déterminée conformément à cet article, exprimée en tonnes,

(B) la quantité d'émissions de CO_2 qui est attribuable à la combustion de combustibles fossiles à l'égard de chaque type de combustible brûlé (E_i), déterminée conformément à l'article 14 du présent règlement et exprimée en tonnes,

(C) la quantité d'émissions de CO_2 qui provient du sorbant utilisé (E_s) à l'égard de chaque type de combustible brûlé, exprimée en tonnes;

c) à l'égard de chaque type de combustible brûlé par le groupe :

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(ii) the quantity of fuel combusted;

(d) in respect of the quantity of electricity generated by the unit,

(i) that quantity determined in accordance with subsection 18(1) of these Regulations, expressed in GWh, and

(ii) the values determined for G_{gross} and G_{ec} in the formula set out in subsection 18(1) of these Regulations, expressed in GWh; and

(e) the weighted average of the carbon content of the fuel (CC_A), determined in accordance with subsection 14(2) of these Regulations, for each fuel combusted, along with an indication of which ASTM standard or method, including using a direct measuring device, was used for each calculation.

4 The following information with respect to the unit:

(a) the values determined for E_{th}, E_{ccs}, E_{ext} and E_{ec}, in the formula set out in section 8 of these Regulations, expressed in tonnes;

(b) the values determined for H_{pnet}, h_{out_i}, M_{out_i}, h_{in_j} and M_{in_j} used to determine E_{th} in accordance with section 15 of these Regulations, expressed in GJ, tonnes, or GJ/tonne, as applicable;

(c) the values determined for E_{cap} and E_{in}, used to determine E_{ccs} in accordance with section 16 of these Regulations, expressed in tonnes;

(d) the values determined for E_k, P_k and Q_k, used to determine E_{ext} in accordance with section 17 of these Regulations, expressed in tonnes or GJ, as applicable;

(e) the values referred to in section 3 of this Schedule for any calculation done in accordance with subsection 8(2) of these Regulations;

(f) the result of the formula in subsection 18(1) of these Regulations, expressed in GWh;

(g) the value determined for G_{gross} in the formula set out in subsection 18(1) of these Regulations, expressed in GWh;

(h) the value determined for G_{ec} in the formula set out in subsection 18(1) of these Regulations, expressed in GWh; and

(i) its net exports, expressed in GWh, during the previous calendar year.

(i) le type et, s'il s'agit de biomasse, une mention indiquant en quoi ce type est de la *biomasse* au sens du paragraphe 2(1) du présent règlement,

(ii) la quantité brûlée;

d) à l'égard de la quantité d'électricité produite par le groupe :

(i) la quantité déterminée conformément au paragraphe 18(1) du présent règlement, exprimée en GWh,

(ii) la valeur déterminée pour les variables G_{brute} et G_{su} dans la formule prévue au paragraphe 18(1) du présent règlement, exprimée en GWh;

e) la moyenne pondérée du contenu en carbone du combustible (CC_M) dans la formule prévue au paragraphe 14(2) du présent règlement à l'égard de chaque type de combustible brûlé, ainsi que la mention des normes ASTM, méthodes et instruments de mesure qui ont été utilisés pour chaque calcul.

4 Pour tous les groupes :

a) les valeurs, exprimées en tonnes, déterminées pour les variables E_{th}, E_{csc}, E_{ext} et E_{su} utilisées dans la formule visée à l'article 8 du présent règlement;

b) les valeurs, exprimées en GJ, GJ/tonnes ou tonnes selon le cas, déterminées pour les variables H_{pnette}, h_{sort_i}, M_{sort_i}, h_{intr_j} et M_{intr_j} utilisées dans la formule visée à l'article 15 du présent règlement pour déterminer la variable E_{th};

c) les valeurs, exprimées en tonnes, déterminées pour les variables E_{cap} et E_{in} utilisées dans la formule visée à l'article 16 du présent règlement pour déterminer la variable E_{csc};

d) les valeurs, exprimées en tonnes ou GJ selon le cas, déterminées pour les variables E_k P_k et Q_k utilisées dans la formule visée à l'article 17 du présent règlement pour déterminer la variable E_{ext};

e) les valeurs visées à l'article 3 de la présente annexe pour chaque calcul effectué au paragraphe 8(2) du présent règlement;

f) le résultat de la formule prévue au paragraphe 18(1) du présent règlement, exprimée en GWh;

g) la valeur, exprimée en GWh, déterminée pour la variable G_{brute} dans la formule prévue au paragraphe 18(1) du présent règlement;

h) la valeur, exprimée en GWh, déterminée pour la variable G_{su} dans la formule prévue au paragraphe 18(1) du présent règlement;

i) le solde exportateur au cours de l'année civile précédente.

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5 With respect to a unit for which the Minister has issued an exemption under section 19 or an extension under section 20 of these Regulations, the duration of the emergency circumstance, including the date on which the circumstance arose and the date on which it ceased.

6 With respect to a unit referred to in subsection 6(2) of these Regulations,

(a) the year in which the carbon capture and storage system started operating and documents establishing that the captured CO_2 was captured, transported and stored in accordance with the requirements of subsection 8(4) of these Regulations, and

(b) documentation demonstrating that the unit operated at or below 30 tonnes/GWh for two periods of at least 12 continuous hours, with at least four months between those two periods, in the calendar year for which the annual report is submitted.

7 With respect to a unit referred to in subsection 6(3) of these Regulations, a statement that an exemption referred to in that subsection is being used for the calendar year.

8 If applicable, a copy of the auditor's report referred to in subsection 12(3) of these Regulations.

9 The following information respecting the replacement data referred to in section 22 of these Regulations that was used for a given period during the calendar year, if applicable:

(a) the reason why data required to determine the value of an element of a formula referred to in these Regulations was not obtained and how that reason was beyond the responsible person's control;

(b) the element of the formula for which data was not obtained and the date of the day on which the data was not obtained and, if that data was not obtained for a period of several days, the dates of the days on which the period begins and ends; and

(c) the value determined for the element referred to in paragraph (b) using replacement data, along with details of that determination, including

(i) the data used to make that determination for each period of one or more days,

(ii) the method used to obtain that replacement data, and

(iii) in the case of a determination of the value of an element referred to in subsection 22(3) of these Regulations, a justification for the given period being used as the basis of that determination.

5 Pour tout groupe visé par une exemption accordée en application de l'article 19 du présent règlement ou prolongée en application de l'article 20 de celui-ci, la durée de la situation d'urgence, incluant la date à laquelle la situation a débuté et celle à laquelle elle a pris fin.

6 Renseignement à l'égard d'un groupe visé au paragraphe 6(2) du présent règlement :

a) l'année au cours de laquelle le système de captage et de stockage de carbone a commencé à opérer et les renseignements établissant, documents à l'appui, que les émissions de CO_2 ont été captées, transportées et stockées conformément au paragraphe 8(4) du présent règlement;

b) les documents établissant que le groupe a fonctionné à une intensité inférieure ou égale à 30 tonnes/GWh pendant deux périodes d'au moins douze heures consécutives, ces périodes étant séparées d'au moins quatre mois au cours de l'année civile à l'égard de laquelle le rapport annuel est soumis.

7 S'agissant d'un groupe visé au paragraphe 6(3) du présent règlement, une mention indiquant que l'exemption prévue à ce paragraphe est utilisée pour l'année civile.

8 Le cas échéant, une copie du rapport du vérificateur visé au paragraphe 12(3) du présent règlement.

9 Renseignements sur les données de remplacement utilisées pour une période donnée au cours de l'année civile en application de l'article 22, le cas échéant :

a) la raison pour laquelle les données nécessaires pour déterminer une variable des formules prévues au présent règlement n'ont pas été obtenues et une explication établissant en quoi cette raison est indépendante de la volonté de la personne responsable;

b) la variable de la formule pour laquelle les données n'ont pas été obtenues et la date du jour en cause et, s'il s'agit d'une période de plusieurs jours, la date du début de cette période et la date à laquelle elle a pris fin;

c) la valeur de la variable visée à l'alinéa b) déterminée à l'aide de données de remplacement, et des précisions sur la façon dont elle a été déterminée, notamment :

(i) les données utilisées au cours de toute période d'un ou de plusieurs jours pour faire cette détermination,

(ii) la méthode utilisée pour obtenir les données de remplacement,

(iii) dans le cas de la détermination d'une variable visée au paragraphe 22(3) du présent règlement, la raison qui justifie toute période utilisée pour cette détermination.

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SCHEDULE 3

(Subsections 10(1) and 11(2))

List of Fuels and Default Higher Heating Value

Item	Column 1 Fuel type	Column 2 Default higher heating value	Column 3 Units
1	Distillate fuel oil No. 1	38.78	GJ/kL
2	Distillate fuel oil No. 2	38.50	GJ/kL
3	Distillate fuel oil No. 4	40.73	GJ/kL
4	Kerosene	37.68	GJ/kL
5	Liquefied petroleum gases (LPG)	25.66	GJ/kL
6	Propane[1]	25.31	GJ/kL
7	Propylene	25.39	GJ/kL
8	Ethane	17.22	GJ/kL
9	Ethylene	27.90	GJ/kL
10	Isobutane	27.06	GJ/kL
11	Isobutylene	28.73	GJ/kL
12	Butane	28.44	GJ/kL
13	Butylene	28.73	GJ/kL
14	Natural gasoline	30.69	GJ/kL
15	Motor gasoline	34.87	GJ/kL
16	Aviation gasoline	33.52	GJ/kL
17	Kerosene-type aviation	37.66	GJ/kL
18	Pipeline quality natural gas	0.03793	GJ/m^3 at standard conditions
19	Bituminous Canadian coal — Western	25.6	GJ/tonne
20	Bituminous Canadian coal — Eastern	27.9	GJ/tonne
21	Bituminous non-Canadian coal — U.S.	25.7	GJ/tonne
22	Bituminous non-Canadian coal — other countries	29.9	GJ/tonne

ANNEXE 3

(paragraphes 10(1) et 11(2))

Liste des combustibles et pouvoir calorifique supérieur par défaut

Article	Colonne 1 Type de combustible	Colonne 2 Pouvoir calorifique supérieur par défaut	Colonne 3 Unité
1	Mazout léger nº 1	38,78	GJ/kL
2	Mazout léger nº 2	38,50	GJ/kL
3	Mazout lourd nº 4	40,73	GJ/kL
4	Kérosène	37,68	GJ/kL
5	Gaz de pétrole liquéfié (GPL)	25,66	GJ/kL
6	Propane[1]	25,31	GJ/kL
7	Propylène	25,39	GJ/kL
8	Éthane	17,22	GJ/kL
9	Éthylène	27,90	GJ/kL
10	Isobutane	27,06	GJ/kL
11	Isobutylène	28,73	GJ/kL
12	Butane	28,44	GJ/kL
13	Butylène	28,73	GJ/kL
14	Essence naturelle	30,69	GJ/kL
15	Essence à moteur	34,87	GJ/kL
16	Essence aviation	33,52	GJ/kL
17	Kérosène type aviation	37,66	GJ/kL
18	Gaz naturel de qualité pipeline	0,03793	GJ/m^3 mesuré dans des conditions normales
19	Charbon bitumineux canadien — Ouest	25,6	GJ/tonne
20	Charbon bitumineux canadien — Est	27,9	GJ/tonne
21	Charbon bitumineux non canadien — É.-U.	25,7	GJ/tonne

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Item	Column 1 Fuel type	Column 2 Default higher heating value	Column 3 Units
23	Sub-bituminous Canadian coal — Western	19.2	GJ/tonne
24	Sub-bituminous non-Canadian coal — U.S.	19.2	GJ/tonne
25	Coal — lignite	15.0	GJ/tonne
26	Coal — anthracite	27.7	GJ/tonne
27	Coal coke and metallurgical coke	28.8	GJ/tonne
28	Petroleum coke from refineries	46.4	GJ/tonne
29	Petroleum coke from upgraders	40.6	GJ/tonne
30	Municipal solid waste	11.5	GJ/tonne
31	Tires	31.2	GJ/tonne
32	Diesel	38.3	GJ/kL
33	Light fuel oil	38.8	GJ/kL
34	Heavy fuel oil	42.5	GJ/kL
35	Ethanol	21	GJ/kL
36	Hydrogen	0.012289	GJ/m^3 at standard conditions

[1] The default higher heating value and the default CO_2 emission factor for propane are only for pure gas propane. The product commercially sold as propane is to be considered LPG for the purpose of these Regulations.

Article	Colonne 1 Type de combustible	Colonne 2 Pouvoir calorifique supérieur par défaut	Colonne 3 Unité
22	Charbon bitumineux non canadien — autres pays	29,9	GJ/tonne
23	Charbon subbitumineux canadien — Ouest	19,2	GJ/tonne
24	Charbon subbitumineux non canadien — É.-U.	19,2	GJ/tonne
25	Charbon — lignite	15,0	GJ/tonne
26	Charbon — anthracite	27,7	GJ/tonne
27	Coke de charbon et coke métallurgique	28,8	GJ/tonne
28	Coke de pétrole (raffineries)	46,4	GJ/tonne
29	Coke de pétrole (usines de valorisation)	40,6	GJ/tonne
30	Déchets solides municipaux	11,5	GJ/tonne
31	Pneus	31,2	GJ/tonne
32	Diesel	38,3	GJ/kL
33	Mazout léger	38,8	GJ/kL
34	Mazout lourd	42,5	GJ/kL
35	Éthanol	21	GJ/kL
36	Hydrogène	0,012289	GJ/m^3 mesuré dans des conditions normales

[1] Le pouvoir calorifique supérieur par défaut et le facteur d'émissions de CO_2 par défaut pour le propane s'appliquent uniquement au gaz propane pur. Pour l'application du présent règlement, les produits commerciaux vendus comme étant du propane sont réputés être du GPL.

UNOFFICIAL VERSION NON OFFICIELLE

SCHEDULE 4

(Subsection 12(3))

CEMS Auditor's Report — Information Required

1 The unit's registration number, assigned by the Minister under subsection 4(3) of these Regulations.

2 The name, civic address and telephone number of the responsible person.

3 The name, civic address, telephone number and qualifications of the auditor and, if any, the auditor's email address and fax number.

4 The procedures followed by the auditor to assess whether

(a) the responsible person's use of the CEMS complied with the Quality Assurance/Quality Control manual referred to in Section 6.1 of the Reference Method; and

(b) the responsible person complied with the Reference Method and the CEMS met the specifications set out in the Reference Method, in particular, in its Sections 3 and 4.

5 A statement of the auditor's opinion as to whether

(a) the responsible person's use of the CEMS complied with the Quality Assurance/Quality Control manual referred to in Section 6.1 of the Reference Method; and

(b) the responsible person complied with the Reference Method and the CEMS met the specifications set out in the Reference Method, in particular, in its Sections 3 and 4.

6 A statement of the auditor's opinion as to whether the responsible person has ensured that the Quality Assurance/Quality Control manual has been updated in accordance with Sections 6.1 and 6.5.2 of the Reference Method.

ANNEXE 4

(paragraphe 12(3))

Rapport du vérificateur sur le SMECE — renseignements à fournir

1 Le numéro d'enregistrement du groupe attribué par le ministre en application du paragraphe 4(3) du présent règlement.

2 Les nom, adresse municipale et numéro de téléphone de la personne responsable.

3 Les nom, adresse municipale, numéro de téléphone et titres de compétence du vérificateur et, le cas échéant, son numéro de télécopieur et son adresse électronique.

4 Les procédures utilisées par le vérificateur pour évaluer :

a) si l'utilisation du SMECE par la personne responsable était conforme au manuel d'assurance de la qualité et de contrôle de la qualité visé à la section 6.1 de la méthode de référence;

b) si la personne responsable a suivi la méthode de référence et si le SMECE répondait aux spécifications qui y sont prévues, notamment aux sections 3 et 4.

5 Une déclaration du vérificateur portant qu'à son avis :

a) l'utilisation du SMECE par la personne responsable était conforme au manuel d'assurance de la qualité et de contrôle de la qualité visé à la section 6.1 de la méthode de référence;

b) la personne responsable a suivi la méthode de référence et le SMECE répondait aux spécifications qui y sont prévues, notamment aux sections 3 et 4.

6 Une déclaration du vérificateur portant qu'à son avis la personne responsable a veillé à ce que le manuel d'assurance de la qualité et de contrôle de la qualité soit mis à jour conformément aux sections 6.1 et 6.5.2 de la méthode de référence.

UNOFFICIAL VERSION NON OFFICIELLE

SCHEDULE 5

(subsection 24(3))

Permanent Cessation of Electricity Generation Report

1 The unit's registration number, assigned by the Minister under subsection 4(3) of these Regulations.

2 An attestation dated and signed by the responsible person or their authorized official that the unit has permanently ceased generating electricity.

3 The date on which the unit permanently ceased generating electricity.

ANNEXE 5

(paragraphe 24(3))

Rapport de cessation définitive de production d'électricité

1 Le numéro d'enregistrement du groupe attribué par le ministre en application du paragraphe 4(3) du présent règlement.

2 Une attestation datée et signée par la personne responsable ou son agent autorisé portant que le groupe a cessé définitivement de produire de l'électricité.

3 La date à laquelle le groupe a cessé définitivement de produire de l'électricité.

UNOFFICIAL VERSION NON OFFICIELLE

Projet de règlement sur l'électricité propre

RÉSUMÉ DE L'ÉTUDE D'IMPACT DE LA RÉGLEMENTATION

(*Ce résumé ne fait pas partie du règlement*.)

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Projet de règlement sur l'électricité propre

RÉSUMÉ DE L'ÉTUDE D'IMPACT DE LA RÉGLEMENTATION

(*Ce résumé ne fait pas partie du règlement*.)

Résumé

Enjeux : Il y a un besoin urgent de s'attaquer au changement climatique et le Canada s'est engagé à faire sa part. Alors que le changement climatique rend les conditions météorologiques plus extrêmes et plus instables, les catastrophes liées au climat (par exemple, les inondations, les tempêtes et feux de forêt) deviennent plus fréquentes et plus coûteuses. Les pertes assurées résultant d'événements météorologiques catastrophiques au Canada ont totalisé plus de 18 milliards de dollars (2019 CAD) entre 2010 et 2019, tandis que le nombre d'événements météorologiques catastrophiques au cours de cette période a été plus de trois fois supérieur à ce qu'il était entre 1980 et 1989.[1] Sans atténuation rapide pour réduire les émissions de gaz à effet de serre (GES) afin de maintenir l'augmentation de la température mondiale en dessous de 1,5 °C (degrés Celsius) par rapport aux niveaux préindustriels, les effets néfastes du changement climatique devraient s'intensifier au-delà de la capacité d'adaptation (la capacité des -systèmes écologiques pour s'adapter aux changements environnementaux), affectant de manière disproportionnée les plus vulnérables de notre population[2]. En plus des répercussions catastrophiques sur l'environnement et la santé humaine, les changements climatiques entraîneront également d'importantes pertes sociales, culturelles et économiques au Canada. Afin de limiter ces effets et en se basant sur la conclusion accablante de la science du climat, le Canada a rejoint en 2021 plus de 120 pays qui se sont engagés à devenir, d'ici 2050, une économie carboneutre[3].

Pour parvenir à la carboneutralité dans l'ensemble de l'économie d'ici 2050, l'électrification des activités énergivores, telles que le transport, le chauffage et la climatisation des bâtiments et divers procédés industriels, sera nécessaire. Pour que cette électrification entraîne les répercussions souhaitées, la production d'électricité devra provenir de sources de production d'électricité peu et non émettrices (voir le tableau 3 pour une description de ces technologies) et cela devra se produire bien avant 2050. En considérant par exemple que le gouvernement du Canada (le gouvernement) a proposé un mandat de vente pour s'assurer que 100 % des ventes de véhicules légers seraient des véhicules à zéro émission de GES d'ici 2035,[4] le gouvernement a déterminé que sans réglementation fédérale visant à garantir que le secteur de la production d'électricité fournisse une électricité plus propre à partir de sources de production d'électricité peu et non émettrices d'ici 2035, le secteur ne serait pas sur une trajectoire permettant à l'économie d'atteindre la carboneutralité d'ici 2050.

Description : Le projet de *Règlement sur l'électricité propre* (le projet de règlement) établirait des normes de rendement pour réduire les émissions de GES provenant de l'électricité produite à partir de combustibles fossiles à compter de 2035.

Justification : Le projet de règlement accélérerait les progrès vers un secteur de production d'électricité carboneutre, aidant le Canada à devenir une économie carboneutre d'ici 2050. Ces efforts

[1] *Source* : La pointe de l'iceberg, composer avec les coûts connus et inconnus des changements climatiques au Canada
[2] *Source* : Adaptive capacity beyond the household: a systematic review of empirical social-ecological research - IOPscience
[3] La carboneutralité consiste à réduire les émissions de GES à un niveau aussi près que possible de zéro, les émissions restantes étant réabsorbées de l'atmosphère par les océans et les forêts, par exemple.
[4] *Source*: La *Gazette du Canada*, partie 1, volume 156, numéro 53 : *Règlement modifiant le Règlement sur les émissions de gaz à effet de serre des automobiles à passagers et des camions légers.*

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sont nécessaires pour aider à limiter les pires effets du changement climatique. Le projet de règlement établirait des normes de rendement qui garantiraient une transformation importante du secteur d'ici 2035, de sorte qu'une base solide d'électricité propre soit disponible pour alimenter les technologies électriques (par exemple, le transport électrique) nécessaires pour soutenir la transition du Canada vers une économie carboneutre d'ici 2050.

Une analyse coûts-avantages (ACA) a été réalisée à partir des résultats de deux modèles ministériels, NextGrid et E3MC, de manière à minimiser le coût à l'échelle du système (national) de la satisfaction de la demande d'électricité, sous réserve de nombreuses contraintes, notamment les paramètres des politiques, la fiabilité du réseau et la disponibilité des ressources (par exemple, les contraintes géologiques). L'ACA tient compte de divers changements économiques et environnementaux externes susceptibles de se produire au cours de la période d'analyse en utilisant des hypothèses prudentes, le cas échéant, et en testant d'autres paramètres dans le cadre d'analyses de sensibilité. L'ACA représente une modélisation du cas central dans laquelle la demande d'électricité augmente de 40 % au cours de la période d'analyse. Ce scénario central ne représente pas la seule voie que le secteur de la production d'électricité pourrait emprunter pour se conformer aux exigences réglementaires, qui dépendra en fin de compte des décisions d'investissement prises au niveau provincial. Selon l'ensemble des hypothèses utilisées dans la modélisation du scénario central, l'ACA estime que le projet de règlement entraînerait une réduction nette de 342 millions de tonnes métriques (Mt) d'unités d'équivalent en dioxyde de carbone (CO_2e) d'émissions de GES entre 2024 et 2050 (la période d'analyse de 27 ans). Les avantages supplémentaires associés à ces réductions de GES, en plus des économies de coûts pour le système électrique, sont estimés à 102,5 milliards de dollars, tandis que les coûts supplémentaires sont estimés à 73,6 milliards de dollars sur la période analytique de 27 ans, ce qui se traduit par un avantage net pour la société de 28,9 milliards de dollars (en dollars constants de 2022, actualisés à l'année de référence 2023 à un taux d'actualisation de 2 %).

Enjeux

Il y a un besoin urgent de s'attaquer au changement climatique à l'échelle mondiale et le Canada s'est engagé à faire sa part. Le changement climatique est responsable d'importants phénomènes météorologiques extrêmes, de perturbations de l'approvisionnement alimentaire et d'une augmentation des feux de forêt dans le monde entier. Au cours des cinq dernières décennies au Canada, les coûts annuels des catastrophes météorologiques telles que les inondations, les tempêtes et les feux de forêt sont passés de dizaines de millions de dollars à des milliards de dollars. De 2010 à 2019, le nombre d'événements catastrophiques a été plus de trois fois supérieur à celui des années 1980. Les dommages causés par les catastrophes météorologiques sont parmi les indicateurs les plus visibles des coûts du changement climatique. Pourtant, ces coûts ne donnent qu'une image incomplète puisqu'ils ne représentent pas l'ensemble des dommages sociaux (par exemple, les effets sur la santé humaine), économiques et environnementaux du changement climatique.[5] La planète s'est déjà réchauffée d'environ 1 °C (degré Celsius) par rapport aux niveaux préindustriels (1850-1900) en raison des activités humaines et subit les effets négatifs qui en découlent. Au rythme actuel de 0,2 °C par décennie, le réchauffement de la planète atteindra 1,5 °C entre 2030 et 2052.[6] En l'absence de mesures d'atténuation rapides visant à réduire les émissions de GES afin de limiter le réchauffement à 1,5 °C, les effets néfastes du changement climatique devraient s'aggraver au-delà de la capacité d'adaptation, affectant de manière disproportionnée les membres les plus vulnérables de notre société. En 2021, le Canada a rejoint plus de 120 pays en s'engageant à mettre en place une économie carboneutre d'ici 2050[7] afin de limiter le réchauffement planétaire à 1,5 °C et éviter les pires effets du changement climatique.

[5] *Source*: La pointe de l'iceberg, composer avec les coûts connus et inconnus des changements climatiques au Canada
[6] *Source*: Summary for Policy Makers. What the IPCC Special Report on Global Warming of 1.5°C means for cities
[7] *Source*: La carboneutralité d'ici 2050 - Canada.ca

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Pour parvenir à la carboneutralité dans l'ensemble de l'économie d'ici 2050 et pour que cette électrification entraîne les répercussions nécessaires, il faudra électrifier les activités à forte consommation d'énergie, telle que le transport[8], le chauffage et la climatisation des bâtiments ainsi que divers processus industriels. Même en l'absence de mesures réglementaires visant à contrôler les émissions de dioxyde de carbone du secteur de l'électricité, ce besoin en électrification exigera des investissements importants pour maintenir, moderniser et développer les parcs de générateurs d'électricité du Canada. Les estimations préliminaires du ministère indiquent que ces investissements devraient s'élever à plus de 400 milliards de dollars. Pour que l'électrification ait l'impact requis sur la réduction des GES, les investissements devront être orientés vers la production d'électricité à faibles émissions et sans émissions (voir le tableau 3 pour une description de ces technologies) et cela devra se produire bien avant 2050. Sans réglementation fédérale pour s'assurer que le secteur de la production d'électricité est prêt à fournir de l'électricité plus propre à partir de sources de production d'électricité peu et non émettrices d'ici 2035, le secteur ne serait pas sur la voie qui permettrait à l'économie d'atteindre la carboneutralité d'ici 2050.

Contexte

Il est urgent de lutter contre le changement climatique et de respecter les engagements pris par le Canada en la matière.

La réduction des émissions mondiales de GES visant la carboneutralité d'ici 2050 est le meilleur moyen de limiter les risques graves liés au changement climatique en raison du réchauffement de la planète. Les GES font naturellement partie des systèmes géologiques de la Terre, mais les activités humaines, telles que l'utilisation de combustibles fossiles, augmentent rapidement les niveaux de GES dans l'atmosphère. Cette concentration accrue de GES dans l'atmosphère augmente la température à la surface de la Terre (réchauffement planétaire), provoquant ainsi le changement climatique. L'augmentation des températures à la surface de la planète entraîne la probabilité d'une augmentation des sécheresses et de l'intensité des tempêtes. L'évaporation d'une plus grande quantité d'eau dans l'atmosphère alimente des tempêtes de plus en plus puissantes. L'augmentation de la chaleur dans l'atmosphère et le réchauffement des températures à la surface des océans peuvent entraîner une augmentation de la vitesse des vents dans les tempêtes tropicales. L'élévation du niveau de la mer expose des endroits qui n'étaient pas soumis auparavant à la puissance et à la capacité destructrices des océans, notamment aux forces érosives des vagues et des courants. La terre s'est déjà réchauffée d'environ 1 °C par rapport aux niveaux préindustriels en raison des activités humaines et en subit les conséquences. En 2022, le Groupe d'experts intergouvernemental sur l'évolution du climat (GIEC) a publié le rapport intitulé *Changement climatique 2022 : Impacts, adaptation et vulnérabilité*, qui évalue que le changement climatique, notamment l'augmentation de la fréquence et de l'intensité des phénomènes climatiques et météorologiques extrêmes, a eu des effets néfastes généralisés sur les écosystèmes, l'agriculture, l'alimentation, l'eau, la santé humaine, les moyens de subsistance et l'activité économique. En affectant de manière disproportionnée les plus vulnérables, notamment par ses effets sur l'alimentation, l'eau et les moyens de subsistance, le changement climatique peut exacerber les inégalités et les injustices

[8] Le plan de réduction des émissions comprenait un engagement à introduire un objectif réglementé de ventes de véhicules à émissions nulles qui exigerait que 100 % des ventes de voitures aux particuliers et de camionnettes soient des véhicules à émissions nulles d'ici 2035, avec des objectifs intermédiaires d'au moins 20 % d'ici 2026 et d'au moins 60 % d'ici 2030. Le projet de règlement a été publié dans la partie 1 de la *Gazette du Canada* le 31 décembre 2022.

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existantes, tant au niveau national que mondial. La base de données canadienne sur les catastrophes (BDC) recense les risques météorologiques les plus importants, en termes de fréquence, de coût et de personnes déplacées. La BDC estime que les coûts des catastrophes naturelles se sont élevés à 35 milliards de dollars (en dollars canadiens de 2019) pour 300 des 645 catastrophes liées aux conditions météorologiques enregistrées depuis 1970. Les inondations sont les catastrophes météorologiques les plus fréquemment signalées, avec 40 % du nombre total de catastrophes naturelles, suivies par les orages violents (18 %), les feux de forêt (15 %) et les tempêtes hivernales (9 %). La grêle, le vent et le verglas sont inclus dans ces catégories. Le nombre annuel de catastrophes dans la BDC n'a cessé d'augmenter depuis les années 1970, fluctuant entre un minimum de huit au début des années 1970 et un maximum de 27 par an en 2016. En plus de cette augmentation du nombre de catastrophes naturelles, les coûts par catastrophes ont aussi augmentés, passant d'une moyenne de 8,3 millions de dollars (2019 CAD) par événement dans les années 1970 à une moyenne de 112 millions de dollars (2019 CAD) par événement dans les années 2010. Ce changement représente une augmentation de 1 250 % en quatre décennies et demie.[9]

Au rythme actuel de 0,2 °C par décennie, le réchauffement climatique atteindra 1,5 °C entre 2030 et 2052. Compte tenu des incidences du changement climatique associées à un réchauffement planétaire atteignant déjà 1,0 °C par rapport aux niveaux préindustriels, une augmentation à court terme du réchauffement planétaire atteignant 1,5 °C entraînerait une augmentation inévitable de multiples dangers et présenterait des risques pour les écosystèmes et les êtres humains au-delà de la capacité d'adaptation. Les mesures à court terme qui permettraient de limiter le réchauffement planétaire à 1,5 °C réduiraient considérablement les risques futurs par rapport à des niveaux de réchauffement plus élevés. Les effets du changement climatique généralisé sont déjà évidents dans de nombreuses régions du Canada et devraient s'intensifier à l'avenir. Outre les pertes environnementales importantes, notamment la disparition accélérée d'habitats et d'espèces, ce phénomène aura des répercussions négatives sur la vie sociale (par exemple, les effets sur la santé humaine), culturelle et économique du Canada et de ses habitants.

Selon l'Agence internationale de l'énergie,[10] les émissions annuelles mondiales de GES ont augmenté de 60 %, passant de 21,4 gigatonnes (Gt)[11] en 1990 à 34,2 Gt en 2020. Au cours de la même période, les émissions du Canada[12] ont augmenté de 13 %, passant de 595 mégatonnes (Mt) à 672 Mt. Bien que la contribution du Canada aux totaux mondiaux puisse sembler relativement faible, le Canada se classe au **7e rang mondial des émetteurs** de GES par habitant.[13]

Le Canada s'est efforcé de réduire les émissions de GES tant au niveau national qu'international.

Au niveau international

- En 2015, le Canada et 194 autres pays ont conclu les négociations sur l'Accord de Paris ; dans l'Accord, le Canada fixe un objectif de réduction de ses émissions de GES de 30 % par rapport

[9] *Source*: La pointe de l'iceberg, composer avec les coûts connus et inconnus des changements climatiques au Canada
[10] *Source*: Global Energy Review: CO2 Emissions in 2021
[11] 1 gigatonne est égale à 1 000 000 000 tonnes. 1 mégatonne est égale à 1 000 000 tonnes. 1 Kilotonne est égale à 1 000 tonnes. 1 tonne est égale à 1 000 kilogrammes.
[12] *Source:* Rapport d'inventaire national 1990 - 2020.
[13] Émissions de CO_2 (tonnes métriques par habitant) - Canada | Data (banquemondiale.org), pour voir le classement mondial incluant le Canada, téléchargez les données et triez la colonne 2019 du plus élevé au plus bas.

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au niveau de 2005 pour 2030, que le Canada a modifié en 2021 pour se fixer un objectif de réduction des émissions de GES en 2030 de 40 à 45 % par rapport au niveau de 2005.

- En 2021, le Canada a rejoint plus de 120 pays en s'engageant à devenir une économie carboneutre d'ici 2050.

- Le 11 mai 2023, l'Environmental Protection Agency des États-Unis a publié des normes et directives sur les gaz à effet de serre pour les centrales électriques alimentées par des combustibles fossiles.

Au niveau national

- En 2016, le Cadre pancanadien sur la croissance propre et le changement climatique (CPC) : Plan Canadien de lutte contre les changements climatiques et de croissance économique a été publié et comprenait plus de 50 mesures visant à réduire les émissions de GES du Canada, à aider à renforcer la résilience dans tout le pays et à soutenir l'innovation climatique pour une croissance économique propre. Le CPC a été élaboré en collaboration avec les provinces et les territoires du Canada et en consultation avec les organisations autochtones nationales, les parties intéressées et les Canadiens.

- La loi fédérale sur la tarification de la pollution causée par les gaz à effet de serre (LTPGES) est entrée en vigueur le 21 juin 2018. La LTPGES établit le cadre du système fédéral de soutien à la tarification de la pollution par le carbone (mettre un prix sur les GES) qui comprend deux parties : une redevance réglementaire sur les combustibles fossiles comme l'essence et le gaz naturel, la redevance sur les carburants, en vertu de la partie 1 de la LTPGES, et un système d'échange réglementaire pour l'industrie connu sous le nom de Système de tarification fondé sur le rendement (STFR), en vertu de la partie 2 de la LPPCG. Le STFR est conçu pour attribuer un prix à la pollution par le carbone, en incitant les installations industrielles des secteurs présentant un risque important de fuite de carbone et de répercussions sur la compétitivité à réduire leurs émissions de gaz à effet de serre par unité de production. Dans le cadre de l'approche du gouvernement du Canada en matière de tarification de la pollution par le carbone, les provinces et les territoires ont la possibilité de mettre en œuvre un système de tarification du carbone adapté à leur situation, à condition que le système réponde aux critères de rigueur nationaux minimaux (le point de référence fédéral). Depuis 2019, toutes les juridictions du Canada ont mis en place un prix sur la pollution par le carbone.

- En 2020, le plan Un environnement sain et une économie saine, le plan climatique renforcé du Canada pour créer des emplois et soutenir la population, les communautés et la planète a été publié. Il s'appuie sur le CPC et comprend 64 politiques, programmes et investissements fédéraux, nouveaux ou renforcés, visant à réduire la pollution par le carbone et à bâtir une économie plus forte, plus propre, plus résiliente et plus inclusive.

- En 2021, la Loi canadienne sur la responsabilité en matière de carboneutralité (LCRMC) a été promulguée. Cette loi officialise l'objectif du Canada de parvenir à la carboneutralité dans l'ensemble de l'économie d'ici à 2050. Elle fixe une série d'objectifs intermédiaires de réduction des émissions de GES à des étapes quinquennales et exige une série de plans et de rapports pour aider le Canada à franchir ces étapes sur la voie de cet objectif. Conformément à la LCRMC, le Groupe consultatif pour la carboneutralité (GCPC) a été créé et a pour mandat de

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fournir des conseils indépendants sur la réalisation de l'objectif canadien d'émissions nettes de GES à l'échelle de l'économie d'ici 2050.[14]

- En mars 2022, le Plan de réduction des émissions pour 2030 (PRÉ 2030) : Prochaines étapes du Canada pour un air pur et une économie forte a été publié. Le PRÉ 2030 comprend les principales mesures que le gouvernement du Canada entend prendre pour atteindre l'objectif de 2030 (réduction des émissions de GES de 40 à 45 % par rapport aux niveaux de 2005), un objectif intérimaire de réduction des émissions de GES pour 2026, une vue d'ensemble des stratégies sectorielles pertinentes et un calendrier prévisionnel de mise en œuvre de ces mesures. Le PRÉ 2030 constitue une feuille de route pour parvenir une économie carboneutre d'ici 2050.

Stratégie du Canada en matière de changement climatique pour la production d'électricité

Selon le Rapport d'inventaire national 2022 du Canada (RIN 2022),[15] partie 3, en 2020, le Canada a produit 575 000 gigawattheures (GWh)[16] d'électricité et a émis 62 Mt d'équivalent de dioxyde de carbone (CO_2), abrégé en CO_2 e,[17] (9,2 % des émissions nationales totales de GES). Sur l'électricité produite cette année-là, 16 % provenaient de sources d'électricité émettrices utilisant des combustibles fossiles (charbon, gaz naturel, autres combustibles tels que les produits pétroliers raffinés) pendant que 84 % provenaient de sources d'électricité peu et non émettrices utilisant des sources d'énergie renouvelable (nucléaire et autres telles que l'hydroélectricité, l'éolienne et le solaire. Le tableau 1 présente une répartition de la production d'électricité par sources d'électricité émettrices, peu émettrices et non émettrices et des émissions de CO_2e par région en 2020.

Tableau 1. Production d'électricité (GWh) par des sources d'électricité émettrices, peu et non émettrices, et émissions de CO_2e (kt) par région en 2020.

Région	Production d'électricité (GWh)	% de production à partir de sources d'électricité peu et non émettrices	% de la production provenant de sources émettrices	Émissions de CO_2 e (kt) provenant de la production d'électricité émettrice
T.-N.-L.	39 800	97 %	3 %	950
Î.-P.-É.	660	100 %	0 %	0,3
N.-É.	9 420	21 %	79 %	6 340
N.-B.	12 000	70 %	30 %	3 470
Qué.	188 000	99%	1%	290

[14] Depuis lors, le GCPC a fourni des conseils dans de nombreuses publications, telles que *Net-Zero Pathways Initial Observations*, ainsi que *Advice for Canada's 2030 Emissions Reduction Plan* (Observations initiales et conseils concernant le plan de réduction des émissions 2030 du Canada).

[15] *Source* : Site web du RIN 2022, téléchargez le fichier « can-2022-nir-14apr22.zip » pour voir les parties 1, 2 et 3 du RIN 2022.

[16] Le gigawattheure, abrégé en GWh, est une unité d'énergie représentant un milliard (1 000 000 000) de wattheures et équivalant à un million de kilowattheures. Le gigawattheure est souvent utilisé pour mesurer la production des grandes centrales électriques.

[17] L'équivalent en dioxyde de carbone ou CO_2, abrégé en CO_2 e, est une mesure métrique utilisée pour comparer les émissions de divers gaz à effet de serre sur la base de leur potentiel de réchauffement planétaire (PRP), en convertissant les quantités d'autres gaz en quantité équivalente de dioxyde de carbone ayant le même potentiel de réchauffement planétaire.

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Ont.	149 000	94 %	6 %	3 710
Man.	37 200	100%	0%	28
Sask.	24 000	22 %	78 %	13 900
Alb.	55 800	15 %	85 %	32 700
C.-B.	58 400	97 %	3 %	420
Yn.	530	83 %	17 %	54
T.N.-O.	350	74 %	26 %	62
Nt.	200	0 %	100 %	150
Canada	575 000	84 %	16 %	62 100

Le RIN 2022 montre que les émissions de GES provenant de production d'électricité émettrice ont été réduites de plus de moitié, passant de 132 Mt de CO_2e en 2000 à 62 Mt de CO_2e en 2020, alors que la production d'électricité, qui était de 539 000 GWh en 2000, n'a pas fluctué de manière significative. Le tableau 2 présente une répartition par sources de production d'électricité émettrices, peu émettrices, et non émettrices en 2000 et 2020 au Canada.

Tableau 2. Production d'électricité (GWh) par sources de production d'électricité émettrices (Charbon, Gaz naturel, autres carburants), peu et non émettrices (nucléaire, hydro, autre renouvelables) pour le Canada en 2000 et 2020.

Génération d'électricité (GWh) par carburant	Charbon	Gaz naturel	Autres carburants	Nucléaire	Hydro	Autres renouvelables	Génération d'électricité totale (GWh)	Émissions de CO_2 e (kt) provenant de génération d'électricité émettrice
2000	106 440	26 616	13 250	68 650	323 130	260	538 346	132 044
% total de génération d'électricité	20 %	5 %	2 %	13 %	60 %	0,05 %	100 %	-
2020	35 940	47 978	7 346	92 590	354 980	36 180	575 013	62 197
% total de génération d'électricité	6 %	8 %	1 %	16 %	62 %	6 %	100 %	-

Le tableau 2 montre que les réductions d'émissions de GES de 2000 à 2020 étaient principalement dues à une diminution significative de l'utilisation du charbon comme combustible pour produire de l'électricité (de 20 % en 2000 à 6 % en 2020) et à l'adoption de sources de production d'électricité peu émettrices et non émettrices (de 73 % en 2000 à 84 % en 2020).

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Actions fédérales (réglementaires et non réglementaires) visant à soutenir la réduction des émissions de GES du secteur émetteur de la production d'électricité

Le Canada continue de chercher activement à réduire les émissions de GES du secteur de la production d'électricité, notamment par des mesures réglementaires et non réglementaires au niveau fédéral, incluant :

Mesures réglementaires

- La *Loi canadienne sur la protection de l'environnement (1999)* (LCPE ou la Loi) vise à prévenir la pollution et à protéger l'environnement et la santé humaine. Elle fixe des règles pour la prévention et la réglementation des substances toxiques, y compris les GES (par exemple, le dioxyde de carbone et le méthane), et confère au gouverneur en conseil le pouvoir d'adopter des règlements pour gérer la pollution au Canada. Les pouvoirs réglementaires conférés par la LCPE et la LTPGES ont été utilisés pour réduire les émissions de GES du secteur de l'électricité.

- En 2012, le *Règlement sur la réduction des émissions de dioxyde de carbone — secteur de l'électricité thermique au charbon* a été publié dans le but d'établir un régime réglementaire visant à réduire les émissions de CO_2 résultant de la production d'électricité conventionnelle au charbon.

- En 2018, le *Règlement modifiant le Règlement sur la réduction des émissions de dioxyde de carbone — secteur de l'électricité thermique au charbon* a été publié pour accélérer la réduction des émissions de CO_2 provenant de la production d'électricité conventionnelle au charbon d'ici 2030 afin d'aider le Canada à respecter son engagement de réduction des émissions de GES dans le cadre de l'Accord de Paris.

- En 2018, le gouvernement a publié le *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel* afin de limiter les émissions de CO_2 provenant de l'utilisation du gaz naturel comme combustible pour produire de l'électricité au Canada.

- Depuis 2019, le système fédéral de tarification de la pollution par le carbone est en place dans les juridictions qui en ont fait la demande ou qui ne disposent pas d'un système répondant aux critères nationaux minimaux de rigueur (le point de référence fédéral). La tarification du carbone s'applique aux secteurs industriels, y compris le secteur de l'électricité, par l'intermédiaire du système de tarification fondé sur le rendement (STFR) ou d'un système provincial de tarification du carbone applicable.[18] Ces systèmes, y compris le STFR, sont conçus pour inciter les entreprises à réduire leurs émissions de gaz à effet de serre et à stimuler l'innovation tout en maintenant la compétitivité et en protégeant contre les fuites de carbone. Dans le cadre du STFR, les installations industrielles sont soumises à un prix du carbone sur la part de leurs émissions de GES qui dépassent la limite d'émissions de l'installation qui est déterminée en fonction des normes de rendement applicables. À partir de 2030, les capacités de production d'électricité à partir de combustibles gazeux répondant à des critères spécifiques et mises en place à partir du 1er janvier 2021, qu'il s'agisse d'installations existantes ou nouvelles, seront

[18] La plupart des juridictions canadiennes ont leur propre système de tarification du carbone pour l'industrie. En 2022, le STFR fédéral s'appliquait au Manitoba, à l'Île-du-Prince-Édouard, au Yukon, au Nunavut et partiellement à la Saskatchewan.

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entièrement exposées au prix du carbone. Toute capacité de production d'électricité existant avant 2021 ne serait soumise au prix du carbone que pour la partie des émissions de GES dépassant une norme de rendement de 370 t/GWh.

Mesures non réglementaires

- Depuis 2016, le gouvernement du Canada a dirigé plus de 50 milliards de dollars d'investissements ciblés vers la construction de réseaux électriques carboneutre au Canada. Cela comprend des programmes tels que le Programme des énergies renouvelables intelligentes et de trajectoires d'électrification (ÉRITE), un programme de 1,57 milliard de dollars, dont 600 millions de dollars annoncés dans le budget 2022, qui fournit un soutien aux projets d'énergie renouvelable intelligente et de modernisation du réseau électrique, y compris les projets qui soutiennent le renforcement des capacités. De décembre 2021 à février 2023, l'ÉRITE a fourni un financement d'environ 164,5 millions de dollars.[19] Dans le budget 2023, le gouvernement du Canada a annoncé une augmentation du financement de 3 milliards de dollars pour l'ÉRITE.

- Le gouvernement du Canada fournit un financement à faible taux d'intérêt aux projets d'électricité propre par le biais de divers mécanismes, y compris les investissements et le financement de la Banque de l'infrastructure du Canada et du Fonds stratégique pour l'innovation, ainsi que des incitations fiscales fédérales. Ces initiatives totalisent plus de 20 milliards de dollars. Cela comprend :

    - Le Fonds de Croissance du Canada Inc. (15 milliards de dollars pour financer des investissements en faveur d'une économie à zéro émission de gaz à effet de serre) ; et

    - Le budget de 2023 a annoncé une nouvelle cible d'investissement pour la Banque de l'infrastructure du Canada d'au moins 10 milliards de dollars par le biais du domaine prioritaire de l'énergie propre pour la construction d'importantes sources d'électricité propre.

Malgré ces mesures et le fait qu'en 2020, seulement 16 % de l'électricité produite au Canada provenait de sources d'électricité émettrices, l'analyse montre que le secteur canadien de la production d'électricité émettrice n'est pas sur la voie d'une transformation significative de ses émissions d'ici 2035. Pour que le Canada atteigne son objectif de carboneutralité pour l'ensemble de l'économie d'ici 2050, une croissance significative de l'offre d'électricité propre est nécessaire. Les chercheurs s'entendent généralement pour dire que l'utilisation accrue des technologies électriques (p. ex. le transport électrique, le chauffage et la climatisation des bâtiments et les solutions pour divers procédés industriels) pourrait, en l'absence d'une norme sur l'électricité propre, entraîner une augmentation importante des émissions de GES provenant de la production d'électricité à partir de combustibles fossiles (voir la section sur l'analyse de sensibilité).

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[19] *Source*: Projets financés à ce jour - Programme des énergies renouvelables intelligentes et de trajectoires d'électrification (canada.ca)

Technologies actuelles et émergentes du réseau électrique nécessaires pour parvenir à la carboneutralité

Un large éventail de technologies de production d'électricité sont disponibles au Canada pour former le réseau électrique (tel que décrit dans le tableau 3).

Tableau 3. Technologies du réseau électrique et résumé des spécifications en 2022 (moyenne canadienne, dollars constants de 2022)*.

Technologie	Description	Coût du capital ($/kW)	Coût fixe d'exploitation et de maintenance ($/kW)	Coût variable d'exploitation et de maintenance ($/MWh)	Coût moyen du combustible ($/MWh)	Durée de vie estimée (années)
TCPG	Turbine à combustion de pétrole/gaz (semblable au cycle de Brayton)	1 625	20	6	61	45
CCPG	Turbine à combustion pétrole/gaz équipée d'un système de récupération de la chaleur perdue et d'une turbine à vapeur (semblable au cycle de Brayton + cycle de Rankine)	1 571	26	4	61	45
Petit CCPG	Similaire à l'OGCC, mais avec une capacité de production plus faible	1 737	33	4	61	45
GN CSC	Turbine à combustion au gaz naturel (généralement OGCC, mais OGCT possible), équipée d'une technologie de capture et de stockage du carbone.	3 310	51	11	61	45
Vapeur PG	Turbine à vapeur (apparentée au cycle de Rankine) générée à partir de la combustion de pétrole/gaz	5 239	135	9	56	45
Charbon	Production d'une turbine à vapeur à partir de la combustion du charbon	3 825	47	3	13	45
Charbon CSC	Production d'une turbine à vapeur à partir de la combustion du charbon, équipée d'une technologie de capture et de stockage du carbone	8 111	95	11	13	45
Biomasse	Production thermique utilisant la biomasse comme combustible	5 634	138	10	3	45
Biomasse CSC	Production thermique utilisant la biomasse comme combustible, équipée d'une technologie de stockage et séquestration du carbone	10 485	192	18	3	45
Déchets	Production thermique utilisant des déchets comme combustible	2 085	27	8	13	45

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Nucléaire	Production de turbines à vapeur utilisant la fission nucléaire comme source de chaleur	9 120	167	4	-	60
Hydro, charge de base	Projets hydroélectriques avec peu ou pas de stockage (au fil de l'eau)	7 071	137	-	-	100
Hydro en période de pointe	Projets hydroélectriques avec réservoirs associés, capables de produire de l'électricité pendant les périodes de pointe de la demande	7 200	49	2	-	100
Hydroélectricité par pompage	Projets hydroélectriques capables de stocker l'énergie en vue d'une utilisation ultérieure	7 200	49	2	-	100
Petites centrales hydroélectriques	Similaire à l'hydroélectricité de base, mais avec une capacité de production plus faible	4 362	49	2	-	100
Éolien terrestre	Éoliennes terrestres	2 117	51	-	-	30
L'énergie éolienne en mer	Éoliennes en mer	6 370	148	-	-	30
PV solaire	Panneaux solaires photovoltaïques	1 825	18	-	-	30
Géothermie	Production thermique utilisant l'énergie géothermique pour produire de la vapeur	11 712	224	7	-	30
Vague	Processus qui utilise le mouvement des vagues pour produire de l'énergie	8 905	439	-	-	20
Stockage	Technologies variables capables de consommer de l'énergie à un moment donné et de la restituer à un autre moment, avec une perte d'efficacité associée.	1 409	11	1	-	15
Autres	Autres technologies non couvertes ci-dessus	5 462	172	7	32	45

* Toutes les estimations de coûts figurant dans ce tableau ont été calculées à l'aide du modèle ministériel E3MC. Pour plus d'informations sur ce modèle, voir la section Avantages et coûts.

** Le CSC représente le captage et le stockage du carbone des émissions.

D'une manière générale, les technologies des réseaux électriques présentées dans le tableau 3 peuvent être classées dans les catégories suivantes : production d'électricité sans dispositif de réduction des émissions, production d'électricité avec dispositif de réduction des émissions, production d'électricité non émettrice et stockage. Certaines technologies de production d'émissions sans dispositif de réduction des émissions sont capables d'atteindre des profils d'émissions plus faibles en utilisant des « combustibles propres » tels que le gaz naturel renouvelable ou l'hydrogène. Les technologies de production peu émettrices atteignent des profils d'émissions plus faibles en déployant des technologies de réduction telles que le captage et le stockage du carbone (CSC), qui peuvent être construites sur mesure ou installées dans certaines installations existantes.

Il existe également des technologies émergentes pour les réseaux électriques qui pourraient devenir plus largement disponibles au Canada au fur et à mesure de leur développement. Par exemple, les piles à combustible pourraient offrir un stockage d'énergie à plus long terme que les batteries (des mois ou des années contre des jours ou des semaines), mais elles sont actuellement sous-utilisées, car la technologie des piles à combustible n'est pas encore suffisamment efficace par rapport aux batteries. Certaines

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technologies avancées de production d'énergie renouvelable variable, telles que l'éolien en mer et la géothermie, devraient devenir davantage disponibles à moyen terme (bien que soumises à des contraintes géologiques), tout comme les petits réacteurs nucléaires modulaires, qui sont conçus pour être plus largement déployables que le nucléaire conventionnel en raison de leur taille compacte. La production avec dispositif de réduction des émissions, la production sans émissions et le stockage devraient tous contribuer de manière significative au futur réseau électrique carboneutre du Canada, bien qu'un certain degré de développement technologique soit nécessaire pour y parvenir.

Objectif

Les objectifs du projet de règlement sont les suivants :

1. Aider le Canada à respecter ses engagements en matière de changement climatique visant à atteindre la carboneutralité dans l'ensemble de l'économie d'ici 2050, en limitant les émissions provenant de la production d'énergie thermique sans dispositif de réduction des émissions. Cette transition soutiendra les efforts mondiaux pour lutter contre le changement climatique et contribuera à limiter les dommages associés ; et
2. réduire les émissions de GES (c'est-à-dire de CO_2) provenant de la production d'électricité à partir de 2035.

Description

Le projet de règlement permettrait de réduire les émissions en appliquant, aux groupes de production d'électricité, une norme de rendement annuelle en matière d'émissions de 30 tonnes de CO_2 par GWh d'électricité produite (« 30 t/GWh »), avec des exceptions limitées.

Le projet de règlement s'applique à tous les groupes de production d'électricité qui répondent aux critères d'applicabilité. Un groupe est un ensemble d'équipements qui fonctionnent ensemble pour produire de l'électricité et doit comprendre au moins une chaudière ou un moteur à combustion, et peut inclure des systèmes de CSC.

De plus amples informations sur la raison d'être de la réglementation figurent à l'annexe 1.

Application

Le projet de règlement s'applique à tout groupe qui répond aux trois critères suivants :

1. Utilise n'importe quelle quantité de combustibles fossiles pour produire de l'électricité ;
2. A une capacité de 25 MW ou plus ; et,
3. Est connecté à un réseau électrique soumis aux normes de la North American Electric Reliability Corporation (NERC).

Inscription

Le projet de règlement exigerait que tous les groupes qui répondent aux critères d'applicabilité s'enregistrent auprès du ministre de l'Environnement d'ici la fin de l'année 2025 ou, pour les groupes mis en service après le 1er janvier 2025, dans les 60 jours suivants la mise en service.

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Normes de rendement en matière d'émissions

La norme de rendement de 30 t/GWh s'appliquerait à partir du :

1. 1er janvier 2035, pour les groupes qui brûlent du charbon ou du coke de pétrole ;
2. 1er janvier 2035, pour tous groupes mis en service le ou après le 1er janvier 2025 ;
3. 1er janvier 2035, pour un groupe qui a augmenté sa capacité de production d'électricité de 10 % ou plus depuis l'enregistrement de celui-ci ;
4. 1er janvier 2035 ou du 1er janvier de l'année au cours de laquelle l'interdiction prévue au paragraphe 4 (2) du *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz nature*[20] commence à s'appliquer à un groupe chaudière ayant subi une modification majeure, c'est-à-dire un groupe qui a cessé de brûler du charbon, selon la plus tardive de ces deux dates ; ou
5. Pour tous autres groupes, la date la plus tardive entre le 1er janvier 2035 ou 20 ans suivant la date de mise en service.

Seuls les groupes qui ont un solde exportateur de plus de zéro gigawattheure au cours d'une année civile donnée sont soumis à la norme de rendement pour cette année-là. Les groupes ayant un solde exportateur de plus de zéro gigawattheure produisent de l'électricité qui est fournie à un réseau d'électricité réglementé par la NERC et, parfois, demandent de l'électricité à ce réseau. Par conséquent, la norme de rendement ne s'applique qu'aux groupes qui fournissent plus d'électricité à un réseau électrique réglementé par la NERC qu'ils n'en demandent.

Exceptions au respect de la norme de rendement annuelle de 30 t/GWh

Au cours d'une année civile donnée, un groupe pourrait se conformer au règlement proposé en utilisant l'une des exceptions suivantes à la norme de rendement annuelle de 30 t/GWh si toutes les conditions liées à ces exceptions sont remplies :

1. Un groupe, autre qu'un groupe alimenté au charbon, qui fonctionne jusqu'à un maximum de 450 heures pas année (450 h/an) ne peut pas émettre plus de 150 kt de CO_2/an (150 kt/an) ; où, par souci de clarté, 450 heures/an correspondant à un fonctionnement 24 heures/jour pendant 18,75 jours/an ; ou

2. Un groupe utilisant le CSC peut émettre au maximum une moyenne annuelle de 40 t/GWh s'il est démontré que ce groupe est capable de fonctionner à 30 t/GWh (c'est-à-dire, pouvant démonter, documentation à l'appui, que le groupe a fonctionné à 30 t/GWh ou moins pendant deux périodes d'au moins 12 heures consécutives, avec au moins 4 mois entre ces deux périodes, au cours d'une année civile donnée). Cette exception n'est possible que jusqu'à sept ans après la mise en service d'un système de captage et de stockage du carbone (CSC) ou jusqu'au 31 décembre 2039, selon la première éventualité.

[20] Pour plus d'informations sur la signification de « modification majeure », voir le paragraphe 3 (4) du *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel.*

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Si toutes les conditions liées aux exceptions ne sont pas remplies au cours d'une année civile donnée, la norme de rendement de 30 t/GWh en moyenne annuelle doit être respectée au cours de cette année.

En outre, le projet de règlement permettrait à tous groupes assujettis au règlement de fonctionner pendant toutes périodes de circonstances d'urgences accordées par le ministre sans être tenus de respecter la norme de rendement pendant ces périodes de l'année civile. En général, une situation d'urgence est une situation qui survient à la suite d'un événement extraordinaire, imprévu et inévitable.

Quantification

Le projet de règlement définit la manière de déterminer la conformité à la norme de rendement au cours d'une année civile. En général, pour chaque groupe, l'exploitant devra déterminer l'intensité des émissions du groupe, c'est-à-dire les émissions totales du groupe divisées par sa production totale. Les exigences de quantification s'appliquent à chaque groupe, chaque année, à compter de l'année civile au cours de laquelle l'interdiction s'applique pour la première fois au groupe, que le groupe soit ou non soumis à l'interdiction au cours d'une année civile.

La production totale du groupe est la quantité d'électricité qu'il a produit au cours d'une année, mesurée sur une base brute.

Les émissions totales du groupe, qui peuvent être déterminées à l'aide d'une méthode basée sur les combustibles ou d'un système de mesure et d'enregistrement en continu des émissions (SMECE), comprennent, selon le cas, les éléments suivants :

- La quantité d'émissions produites par la combustion de combustibles fossiles pour la production d'électricité ; et
- La quantité d'émissions associées à la production d'hydrogène ou de vapeur utilisée par le groupe pour produire de l'électricité, quel que soit le lieu où est situé le fournisseur.

Par souci de clarté, lorsque l'hydrogène est utilisé comme combustible dans le groupe de production d'électricité, la combustion de cet hydrogène ne produit pas directement d'émissions de CO_2 ; par conséquent, toutes les émissions de CO_2 associées à la production d'hydrogène doivent également être quantifiées et incluses dans les émissions totales du groupe.

Comme le prévoit le projet de règlement, les émissions totales du groupe peuvent exclure la quantité d'émissions captées par son système de CSC uniquement si ces émissions sont stockées de manière permanente dans un projet de stockage répondant aux critères prescrits.

Rapports

Le projet de règlement exigerait que tous les groupes qui répondent aux critères d'applicabilité soumettent un rapport d'enregistrement comprenant des informations telles que : l'identification de la personne responsable, l'emplacement et le nom du groupe, un diagramme de processus du groupe, y compris la date de mise en service de chaque chaudière ou moteur à combustion, la date de mise en service du groupe et la capacité de production d'électricité du groupe.

Sur une base annuelle, le projet de règlement exigerait que tous les groupes qui ont un solde exportateur supérieur à zéro gigawattheure vers un réseau électrique sujet aux normes de la NERC soumettent un

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rapport comprenant des informations telles que l'intensité moyenne annuelle des émissions du groupe et, le cas échéant, dans le cas des groupes dotés d'un système de CSC installé au cours des sept dernières années, la documentation démontrant que le groupe a fonctionné à 30 t/GWh ou moins pendant deux périodes d'au moins 12 heures continues au cours de l'année de déclaration, la production brute, les émissions et les heures d'exploitation.

Une déclaration d'absence de solde exportateur supérieur à zéro gigawattheure peut être fournie pour un groupe qui ne prévoit pas de solde exportateur supérieur à zéro gigawattheure à partir du moment où la norme de rendement commencerait à s'appliquer à ce groupe, ce qui réduirait ses exigences en matière de rapports. Si ces groupes n'ont jamais un solde exportateur supérieur à zéro gigawattheure vers le réseau électrique, ils resteront exemptés à la fois de l'interdiction et des exigences de quantification prévues par le projet de règlement.

Tous les groupes seraient tenus de suivre leur solde exportateur, car la norme de rendement s'appliquerait à partir de l'année applicable (à partir de 2035) pour ce groupe s'il y a un solde exportateur supérieur à zéro gigawattheure cette année-là. Ces groupes seraient également soumis aux règles de quantification à partir de l'année applicable.

Le *Règlement sur les dispositions réglementaires désignées aux fins de contrôle d'application — Loi canadienne sur la protection de l'environnement (1999)* serait modifié afin d'y inclure le projet de règlement et de rendre sa violation des règles applicables passible de sanctions appropriées, telles que des amendes plus élevées et des peines d'emprisonnement.

Élaboration de la réglementation

Consultation

Le ministère de l'Environnement (le ministère) a débuté les consultations avec les parties intéressées par le projet de règlement en mars 2022. Les parties intéressées comprennent les entreprises de services publics, les gouvernements provinciaux et territoriaux, les groupes autochtones, les associations industrielles, les organisations non gouvernementales environnementales (ONGE), les syndicats et les organisations syndicales, les chercheurs et les universitaires dans le domaine du changement climatique ou de l'énergie, ainsi que le grand public.

Tout d'abord, le *document de travail sur la norme sur l'électricité propre* a présenté la proposition initiale du ministère sur la manière de réaliser une transition vers une électricité carboneutre et introduit les éléments clés que toute politique de ce type devrait intégrer, à savoir les réductions d'émissions, l'abordabilité de l'électricité, et la fiabilité du réseau électrique. Dans sa proposition, le ministère a indiqué que la mise en œuvre du projet de règlement nécessiterait un équilibre entre ces trois critères, étant donné que la maximisation des résultats pour l'un des critères pourrait compromettre la réalisation de l'un des deux autres. Par exemple, maximiser l'accessibilité financière pourrait compromettre les réductions d'émissions, car l'option la moins chère pour maintenir le réseau électrique en fonctionnement dans de nombreux endroits est de continuer à utiliser la production existante à base de gaz naturel. De la même manière, maximiser la fiabilité peut entraver les réductions d'émissions, car la fiabilité dans le statu quo exige de disposer d'une production suffisante de gaz naturel. Un réseau électrique qui n'est ni abordable ni fiable pourrait décourager la transition vers une production d'électricité propre nécessaire pour atteindre l'objectif de carboneutralité dans l'ensemble de l'économie en 2050.

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Engagement des parties intéressées

- Le 15 mars 2022, les parties intéressées ont été invitées à soumettre leurs commentaires sur le *document de travail sur la norme sur l'électricité propre*, qui présente l'approche du projet de règlement pour soutenir la carboneutralité dans le secteur de l'électricité d'ici 2035.
- Les 23 et 24 mars 2022, les parties intéressées ont été invitées à participer à un webinaire d'information, intitulé « Ouvrir la boucle », sur le document de travail. Plus de 160 soumissions ont été reçues, un webinaire a été organisé par la suite les 21 et 22 juillet 2022, avec un accent particulier sur ces commentaires.
- Un deuxième cycle d'engagement et de consultation a débuté le 26 juillet 2022, avec la publication du Cadre réglementaire proposé pour le règlement sur l'électricité propre - Canada.ca (« le cadre réglementaire ») qui a fourni plus de détails sur l'approche réglementaire proposée. Plus de 120 soumissions ont été reçues en lien avec ce cadre réglementaire.
- Un troisième webinaire a été organisé les 13 et 14 septembre 2022, avec un accent sur les hypothèses de modélisation. Un certain nombre de sessions de modélisation bilatérales ont été organisées avec diverses provinces pour s'assurer que les hypothèses utilisées dans la modélisation fédérale étaient adéquates.
- Le 3 octobre 2022, une séance d'information a été organisée à l'intention des autochtones, avec la participation de représentants des Premières Nations, ou de leurs représentants.

En date de décembre 2022, près de 100 réunions bilatérales ont eu lieu avec les parties intéressées afin de poursuivre les discussions et de fournir un retour d'information sur l'approche du projet de règlement.

À la suite de ces consultations, plus de 330 soumissions sur la proposition ont été reçues. Les parties intéressées ont formulé des commentaires sur les points suivants :

- Le rôle de la production d'électricité à partir de gaz naturel ou de combustibles liquides après 2035 pour garantir la fiabilité des réseaux ;
- Le traitement des formes de production d'électricité industrielle émettrice ;
- La possibilité d'effets négatifs sur les tarifs de l'électricité ;
- La capacité des nouvelles technologies non émettrices à fournir une électricité fiable d'ici à 2035, en particulier la disponibilité des technologies de production et de stockage.

Les parties intéressées ont également exprimé leur soutien général à la décarbonisation[21] du réseau électrique et leur volonté de participer à l'élaboration du projet de règlement afin de s'assurer qu'il permettrait d'atteindre les réductions d'émissions nécessaires tout en maintenant l'abordabilité et la fiabilité.

En général, les commentaires sur le Cadre réglementaire proposé pour le règlement sur l'électricité propre (26 juillet 2022) ont été positifs, dans la mesure où de nombreuses parties intéressées considèrent le cadre réglementaire proposé comme une approche réalisable pour atteindre la carboneutralité. Cependant, les parties intéressées ont soulevé des préoccupations spécifiques, discutées ci-dessous, que le ministère a examinées en profondeur lors de l'élaboration du projet de règlement.

[21] Réduction ou élimination des émissions de dioxyde de carbone provenant d'un processus tel que la fabrication de bien ou la production d'énergie.

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Préoccupations des parties intéressées

La production d'électricité alimentée au gaz naturel et aux combustibles liquides après 2035 :

De nombreuses entreprises de services publics se sont inquiétées du fait que les opérateurs de réseaux électriques ne seraient pas en mesure de maintenir la fiabilité sans au moins un certain fonctionnement après 2035 des types de production qui sont actuellement alimentés au gaz naturel ou aux combustibles liquides parce qu'ils sont flexibles et hautement contrôlables. Beaucoup ont exprimé leur soutien à une exemption qui permettrait aux exploitants de réseaux d'utiliser ces générateurs pour maintenir la fiabilité, à condition que ce soit sur une base de temps et d'émissions limitées.

Les ONGE, les producteurs d'électricité non émetteurs et les représentants de l'industrie durable ont fait valoir que le rôle du gaz naturel et des combustibles liquides dans la production d'électricité devrait être minime après 2035 et qu'une exigence qui limiterait l'utilisation du gaz naturel réduirait les émissions à un niveau aussi près que possible de zéro.

Pour répondre aux préoccupations des parties intéressées, le ministère a intégré dans le projet de règlement des flexibilités en matière de limites d'émissions pour la production d'électricité alimenté au gaz naturel et aux combustibles liquides :

- Introduire progressivement la norme de rendement pour les groupes existants en appliquant la norme à un groupe donnée 20 ans après sa date de mise en service, appelée fin de vie réglementaire du groupe[22] (FdVR) ;
- Permettre aux groupes assujettis de fonctionner en cas de situations d'urgence sans avoir à respecter la norme de rendement ;
- Permettre aux groupes assujettis de fonctionner pendant des périodes de pointe en dessous d'un seuil d'émissions totales (plutôt que d'une intensité d'émissions) et d'une limite de temps totale au cours d'une année donnée, sans avoir à respecter la norme de rendement ; et
- Fixer la norme de rendement à un niveau (c'est-à-dire 30 t/GWh) qui peut être atteint par les groupes alimentés au gaz naturel avec CSC, de sorte que ces groupes puissent fournir au réseau électrique une production flexible et hautement contrôlable.
    - En outre, le projet de règlement permettrait aux groupes assujettis qui utilisent le CSC dans le cadre d'une stratégie de conformité de respecter une intensité d'émission moyenne annuelle de 40 t/GWh pendant les sept premières années suivant la mise en service du système de captage, ou jusqu'au 31 décembre 2039, selon la première éventualité.

Quelques entreprises de services publics ont mis en garde contre une trop grande flexibilité associée à la production d'électricité au gaz naturel, qui pourrait décourager le déploiement de la production non émettrice et du stockage de l'énergie. En outre, les ONGE se sont inquiétées du fait que tout rôle de la

[22] « fin vie réglementaire » veux dire 1 : Dans le cas d'un groupe chaudière avec modification majeure visé dans le *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel*, la période commençant à la date de mise en service et se terminant à la date à partir de laquelle l'interdiction prend fin à la date à laquelle l'interdiction prévue par ces règlements commence à s'appliquer au groupe ; ou 2. Pour tout autre groupe, la période commençant à la date de mise en service et se terminant à la plus tardive des dates suivantes :

(i) le 31 décembre de l'année civile qui survient vingt ans après la date de mise en service,
(ii) le 31 décembre 2034.

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production d'électricité non urgente alimenté au gaz naturel devrait être fortement limité après 2035. Ces parties ont mis en garde contre une sous-estimation de la capacité des technologies telles que le stockage de l'énergie, l'hydrogène, le CSC, le nucléaire et d'autres technologies émergentes peu ou non émettrices à assurer la fiabilité du réseau électrique d'ici à 2035.

Les délais incorporés dans les quatre flexibilités de conformité susmentionnées pourraient limiter l'utilisation du gaz naturel et des combustibles liquides sans dispositif de réduction des émissions pour la production d'électricité au cours de la période postérieure à 2035. On s'attend à ce que cela conduise à un recours accru à des sources de production peu ou non émettrice.

Les provinces plus émettrices, les services publics, les exploitants de réseaux et les producteurs d'électricité ont demandé une certaine flexibilité dans l'application de la norme de rendement. Plus précisément, ils ont fait part de leur inquiétude quant au fait que, sans flexibilité, la capacité de production alimentée au gaz naturel serait insuffisante pour soutenir les énergies renouvelables variables (par exemple, l'éolien et le solaire) et que les groupes en construction aujourd'hui pourraient ne pas être mis en service à temps (d'ici 2025) pour bénéficier de la FdVR pour les groupes existants décrite ci-dessus.

Pour répondre à cette préoccupation, le projet de règlement prévoit des flexibilités qui :

- Permettent aux groupes assujettis de fonctionner en cas d'urgence ; et
- Permettent aux groupes assujettis de fonctionner s'ils respectent à la fois un seuil d'émissions totales et une limite temporelle totale au cours d'une année donnée (par exemple, exception basée sur la masse à la norme de rendement de 30 t/GWh)

Les ONGE et l'industrie opérant dans le domaine des technologies propres cherchaient des signaux clairs indiquant que le projet de règlement exigerait des opérateurs de réseaux électriques qu'ils répartissent les sources sans émission avant les sources émettrices. En tenant compte de ces commentaires, le ministère a noté que la fiabilité des réseaux électriques est d'une importance cruciale pour les provinces et les territoires, car ceux-ci sont responsables de la conception et de l'exploitation des réseaux. Le projet de règlement fixe une norme de rendement stricte, mais maintient la neutralité technologique, ce qui permet aux provinces et territoires, ou aux opérateurs de réseaux électriques de choisir les types de production à développer.

De nombreuses ONGE ont demandé l'inclusion de normes provisoires (c'est-à-dire l'application d'une norme avant 2035) afin d'éviter l'accumulation de nouvelles centrales alimentées au gaz naturel avant l'application de la norme de rendement en 2035. Le projet de règlement ne propose pas de normes intermédiaires pour les raisons suivantes [23] :

- Étant donné que les nouveaux groupes alimentés au gaz naturel représentent un investissement substantiel qui ne peut être amorti qu'après 10 ans ou plus d'opérations, le ministère s'attend qu'en fixant une norme de rendement de 30 t/GWh à partir de 2035, les nouveaux groupes construits avant 2035 seront néanmoins conçus pour répondre à la norme de rendement de 30 t/GWh afin qu'ils puissent continuer à fonctionner après 2035 ;
- La plupart des groupes alimentés au gaz naturel qui seront mis en service avant 2025 ont été planifiés avant l'annonce du projet de règlement. Peu de groupes pourraient être conçus et

[23] Le projet de règlement prévoit d'autres flexibilités qui peuvent permettre à un groupe de fonctionner sans avoir à respecter la norme de rendement de 30 t/GWh, mais ces flexibilités ne sont pas pertinentes dans le cadre d'une discussion sur la norme provisoire.

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construits avant le 1er janvier 2025, la date à laquelle les groupes sont considérés comme « nouveaux » en vertu du projet de règlement et ne peuvent donc pas bénéficier de la FdVR de 20 ans ; et

- Au lieu de se conformer à la norme de rendement de 30 t/GWh, les groupes peuvent fonctionner à n'importe quelle intensité d'émission pendant un maximum de 450 heures par an, avec une limite de 150 kilotonnes d'émissions par an, pour fournir une capacité d'appoint ou de pointe. Il pourrait être possible de mettre en service, après 2025, un nouveau groupe sans dispositif de réduction des émissions qui pourrait fonctionner selon ces dispositions. Cela présente des avantages pour les régions géographiques du Canada qui n'ont pas accès au stockage géologique profond nécessaire à l'installation des technologies de CSC. Toutefois, on s'attend à ce qu'il soit moins avantageux financièrement d'exploiter un nouveau groupe de façon aussi limité, ce qui limiterait à cette fin la mise en service de nouveaux groupes sans dispositif de réduction des émissions. En outre, les émissions totales de ces groupes seraient inférieures à celles qu'ils produiraient s'ils étaient exploités dans le cadre du plafond de 30 t/GWh.

Traitement de la production industrielle d'électricité émettrice :

De nombreuses ONGE et certains services publics ont fait part de leur inquiétude quant à la possibilité d'un développement important de la production industrielle d'électricité « à l'intérieur des limites d'une installation »[24] afin d'éviter le projet de règlement, étant donné que les groupes d'électricité qui ne sont pas connectés à un réseau électrique réglementé par la NERC ne seraient pas assujettis au projet de règlement.

Après un examen, le ministère a constaté que :

- Le projet de règlement est conçu pour cibler les émissions du secteur de l'électricité. Les émissions industrielles sont soumises à d'autres politiques, telles que la tarification du carbone.
- Le projet de règlement s'appliquerait à tous les groupes de production connectés à un réseau électrique réglementé par la NERC, que ces groupes soient ou non physiquement situés « à l'intérieur des limites d'une installation », c'est-à-dire sur un site industriel.
- Au cours d'une année de conformité donnée, les groupes industriels qui ont un solde exportateur vers un réseau électrique réglementé par la NERC supérieur à zéro gigawattheure (c'est-à-dire qu'ils vendent plus d'électricité qu'ils en achètent) devraient respecter la norme de rendement du projet de règlement au cours de cette année. Cela créera un co-bénéfice, car même l'électricité produite par des groupes ayant un solde exportateur supérieur à zéro gigawattheure, mais utilisé pour répondre à la demande d'électricité sur site, devra respecter la norme de rendement de 30 t/GWh. Cela signifie que seuls les groupes qui n'ont pas un solde exportateur d'électricité vers le réseau supérieur à zéro gigawattheure n'auraient pas à respecter la norme de rendement.
- Les émissions des installations de production d'électricité sont assujetties au Règlement sur le système de tarification fondé sur le rendement (RSTFR) ou par le système provincial ou territorial de tarification du carbone applicable. Cela signifie que les émissions des groupes qui n'ont pas un solde exportateur vers un réseau électrique réglementé par la NERC supérieur à zéro gigawattheure au cours d'une année donnée seront toujours exposées à un signal de prix visant à réduire les émissions.

[24] On entend par « dans les limites de l'installation » un groupe dont la capacité de production d'électricité est adaptée à l'installation industrielle sur laquelle il est situé, de sorte que la majeure partie de son électricité est consommée, la plupart du temps, par l'installation industrielle.

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- À l'heure actuelle, il n'existe pas d'alternatives suffisantes, rentables, et peu ou non émettrices de gaz à effet de serre pour la production entièrement à l'intérieur des limites d'une installation. Dans ce contexte, couvrir les groupes de production d'électricité à base de combustibles fossiles à l'intérieur des limites d'une installation en vertu du projet de règlement lorsque ces groupes n'ont pas de solde exportateur d'électricité supérieure à zéro gigawattheure vers un réseau électrique réglementé par la NERC aurait des effets négatifs sur l'industrie qui ne se produiraient pas dans le cadre des autres politiques décrites ci-dessus (par exemple, la tarification du carbone). En outre, les groupes à l'intérieur des limites d'une installation devraient être pris en compte à mesure que le Canada se dirige vers la carboneutralité en 2050.
- Dans certains cas, les combustibles utilisés pour la production à l'intérieur des limites d'une installation devraient être brûlés à la torche sur le site[25] s'ils n'étaient pas utilisés pour la production d'électricité. Ainsi, si le projet de règlement devait couvrir les groupes à l'intérieur des limites d'une installation, il est probable que de nombreux groupes choisiraient d'éviter la couverture réglementaire en cessant de produire de l'électricité à partir de ces combustibles et en les brûlant à la torche. Dans de tels scénarios, les émissions augmenteraient du fait de l'activité de torchage sans que la combustion apporte de bénéfice (c'est-à-dire de production d'électricité).

Pour les raisons susmentionnées, le projet de règlement ne s'appliquerait pas aux groupes situés à l'intérieur des limites d'une installation qui n'ont pas un solde exportateur supérieur à zéro gigawattheure.

Incidences négatives potentielles sur les tarifs de l'électricité :

Certaines provinces et certains services publics ont fait part de leurs préoccupations concernant les coûts de mise en conformité avec le projet de règlement et les incidences potentielles sur l'abordabilité des tarifs pour les ménages, les entreprises et l'industrie. Ils ont fait remarquer que les réseaux électriques dépendant des combustibles fossiles supporteraient des coûts plus élevés lors de la transition vers la carboneutralité que les réseaux disposant d'importantes ressources sans émission, par exemple l'éolien. Ces parties intéressées ont demandé des programmes de financement, des mesures fiscales et d'autres incitatifs pour minimiser les coûts à court terme de la transition. En particulier, les gouvernements provinciaux du Nouveau-Brunswick et de la Nouvelle-Écosse ont souligné que ces provinces souffrent d'un taux plus élevé de pauvreté énergétique[26] dans le pays, et ont fait part de leur inquiétude quant au fait que le projet de règlement pourrait exacerber ce problème.

Le ministère note que :

- Des consultations spécifiques ont eu lieu concernant l'analyse de l'effet attendu sur les tarifs résidentiels ;
- Indépendamment du projet de règlement et de ses objectifs, le gouvernement du Canada a annoncé, élaboré, et mis en œuvre des mesures complémentaires, y compris des fonds, pour aider à soutenir la transition ver la carboneutralité, réduisant ainsi indirectement les répercussions du projet de règlement sur les tarifs de l'électricité ;

[25] Le brûlage à la torche est la combustion contrôlée de combustible ou de gaz résiduel qui a lieu au cours de certaines formes de production et de traitement. Le combustible ou les déchets gazeux sont enflammés au sommet d'une torchère, ce qui provoque la flamme caractéristique associée au brûlage à la torche. Certaines odeurs peuvent être associées au brûlage à la torche. - Le torchage et la mise à l'air | Association canadienne des producteurs pétroliers (capp.ca)

[26] La pauvreté énergétique est l'incapacité des ménages à s'offrir des services énergétiques ; elle peut se manifester par un dilemme "chauffer ou manger", des coupures de courant auto-imposées pour des raisons financières, ou le maintien de la température de la maison à un niveau inférieur à celui de la température ambiante confortable, *Source* : l'électricité et l'équité dans la transition énergétique du canada

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- le projet de règlement inclurait des flexibilités qui aideraient les services publics à gérer les répercussions des coûts de leur réseau électrique tout en maintenant la fiabilité ; et
- le ministère a collaboré avec un certain nombre d'universitaires spécialisés en économie des réseaux électriques pour comprendre les répercussions potentielles du projet de règlement sur l'abordabilité de l'électricité, ce qui a permis d'établir les normes réglementaires et les marges de manœuvre dans le projet de règlement. Cette collaboration se poursuivra au fur et à mesure que le ministère examinera les commentaires reçus au cours de la période précédant la publication finale.

Capacité des nouvelles technologies non émettrices à fournir une électricité fiable d'ici à 2035

Quelques services publics, ONGE, entreprises actives dans le domaine des technologies propres et quelques universitaires ont mis en garde contre une trop grande flexibilité pour la production de l'électricité alimentée au gaz naturel, car cela pourrait décourager le déploiement de la production sans émission et du stockage de l'énergie. Ces parties ont mis en garde contre une sous-estimation de la capacité des technologies telles que le stockage de l'énergie, les turbines à gaz prêtes pour l'hydrogène, le CSC, le nucléaire et d'autres technologies émergentes peu ou non émettrices pour assurer la fiabilité du réseau électrique d'ici à 2035.

Plusieurs provinces et territoires ont indiqué que le CSC n'était pas une option de décarbonisation pour eux, car leur géologie ne permet pas le stockage du carbone. Plusieurs provinces et territoires ont exprimé leur inquiétude quant à l'état de préparation des technologies clés de décarbonisation telles que le CSC, les petits réacteurs nucléaires modulaires, et le stockage de l'énergie, notant que leurs coûts seront très élevés même lorsqu'elles seront prêtes à être déployées à grande échelle. Les experts en technologie de CSC ont noté que si la norme de rendement de 30 t/GWh peut être atteinte par ces systèmes, il peut y avoir des périodes au cours des premières années de déploiement de ces systèmes où certains ajustements aux systèmes peuvent être nécessaires pour qu'ils atteignent la norme de rendement de manière cohérente.

Le ministère note que :

- De nouveaux investissements dans le développement et le déploiement de technologies émergentes telles que le CSC, le stockage de l'énergie et les petits réacteurs modulaires sont prévus ;
- Les flexibilités en matière de conformité, telles que la durée de vie réglementaire pour les groupes mis en service avant le 1er janvier 2025, ou l'exception relative à la durée et aux émissions basées sur la masse permettent l'utilisation des groupes alimentés au gaz naturel et aux liquides au cours de ces périodes ; et,
- Le projet de règlement contient une exception qui permet à un groupe assujetti doté d'une technologie de CSC de fonctionner à une intensité d'émission moyenne de 40 t/GWh si le groupe peut prouver qu'il est capable de fonctionner à 30 t/GWh (c'est-à-dire fournir de la documentation démontrant que le groupe a fonctionné à 30 t/GWh ou moins pendant deux périodes d'au moins 12 heures consécutives, avec au moins 4 mois entre ces deux périodes au cours d'une année de conformité donnée) et que :
    - Le groupe ne peut utiliser l'exception que pendant les sept années suivant la date de mise en service du système CSC ou jusqu'au 31 décembre 2039, selon la première éventualité.

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- Pendant cette période de sept ans, un groupe dont le système de CSC ne permet pas d'atteindre 30 t/GWh en moyenne annuelle peut continuer à fonctionner pendant que la personne responsable du groupe prend les mesures nécessaires pour améliorer le rendement des émissions du groupe afin qu'il atteigne la norme de rendement de 30 t/GWh en moyenne annuelle. Ces mesures peuvent comprendre plusieurs séries d'essais d'émissions, l'évaluation des défauts de performance du système de CSC, la conception d'une solution permettant un fonctionnement à 30 t/GWh, la construction/mise en œuvre de la solution et sa mise en service. Sur la base des délais associés aux rénovations majeures des groupes de production d'électricité, on estime que sept ans suffiraient amplement pour prendre les mesures nécessaires à l'amélioration des performances du système de CSC. D'ici à 2040, les systèmes de CSC devraient s'être améliorés au point que cette flexibilité ne sera plus nécessaire ; et
- L'exception CSC garantit que les systèmes CSC soient conçus pour atteindre un taux de captage du carbone ambitieux, tout en permettant une certaine flexibilité au cas où des circonstances opérationnelles rendraient difficile l'atteinte initiale de ce taux de manière cohérente.

Obligations découlant des traités modernes et consultation des populations autochtones

Comme l'exige la *Directive du cabinet sur l'approche fédérale pour la mise en œuvre des traités modernes*, une évaluation des implications des traités modernes a été réalisée pour le projet de règlement. L'évaluation a porté sur le champ d'application géographique et l'objet du projet de règlement par rapport aux traités modernes en vigueur. L'évaluation n'a pas mis en évidence de conséquences ou d'obligations découlant de traités modernes.

Le ministère a adopté une approche de consultation basée sur les distinctions avec les peuples autochtones :

- en invitant des représentants d'organisations nationales autochtones (ONA) à des webinaires d'information ;
- en ayant des réunions bilatérales avec les ONA et une offre de poursuivre les réunions sur une base bilatérale ; et
- en organisant un webinaire spécifique pour les Premières Nations afin d'engager une conversation sur le projet de règlement ;

Les parties intéressées autochtones ont indiqué que l'abordabilité de l'énergie était une préoccupation de plus en plus aiguë et ont recommandé que la conception du projet de règlement protège l'abordabilité de l'électricité. Certaines ont également indiqué que les autochtones sont très sensibilisés aux risques pour la santé liés à l'utilisation de combustibles fossiles et qu'ils souhaitent comprendre les avantages de la réduction des polluants atmosphériques que le projet de règlement pourrait entraîner.

Le ministère note que :

- indépendamment du projet de règlement et de ses objectifs, le gouvernement du Canada a annoncé, élaboré et mis en œuvre des mesures complémentaires pour faciliter la transition, notamment du financement destiné à des projets menés par des autochtones ou accessibles à des projets menés par des autochtones, ce qui réduit indirectement les répercussions du projet de règlement sur les tarifs ;

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- le projet de règlement comprendrait des flexibilités qui aideraient les services publics à gérer les répercussions des coûts de leur réseau électrique tout en maintenant la fiabilité ;
- le ministère s'est engagé avec des organisations dirigées par des autochtones ayant connaissance de l'abordabilité de l'énergie dans les communautés autochtones afin de comprendre les répercussions potentielles du règlement sur l'abordabilité de l'électricité. Cet engagement se poursuivra tout au long de l'élaboration du règlement ; et
- les avantages potentiels pour la santé découlant du projet de règlement sont examinés plus en détail dans le présent Résumé de l'étude d'impact de la réglementation (REIR).

Le ministère a également entendu parler des intersections entre le projet de règlement et les préoccupations plus générales concernant la réconciliation économique et la participation des peuples autochtones à la transition vers l'énergie propre, en particulier par le biais de la participation économique.

Outre les considérations ci-dessus, le ministère a examiné toutes les questions et tous les commentaires reçus de la part des parties autochtones intéressées et continuera à les prendre en compte dans l'élaboration du projet de règlements. Certaines questions soulevées, notamment le point de vue des communautés autochtones sur la transition énergétique et la participation économique, présentent un intérêt non seulement dans le contexte du projet de règlement, mais aussi dans celui plus large de la transition vers l'électricité propre.

Choix de l'instrument

La *Directive du Cabinet sur la réglementation* (DCR) exige des ministères et des agences qu'ils évaluent l'ensemble des instruments disponibles (réglementaires et non réglementaires) en vertu des lois et règlements fédéraux afin de sélectionner l'instrument ou la combinaison d'instruments le plus efficace et le plus approprié pour traiter une question de politique générale. Compte tenu de l'urgence de la lutte contre le changement climatique et des objectifs du Canada en la matière, à savoir devenir une économie carboneutre d'ici 2050, un changement transformationnel sera nécessaire dans tous les secteurs de l'économie canadienne, y compris le secteur de la production d'électricité.

La transformation des réseaux électriques doit intervenir bien avant 2050, car elle nécessite une croissance de l'offre d'électricité pour soutenir l'utilisation accrue de technologies électriques, telles que le transport électrique, le chauffage et la climatisation des bâtiments, les solutions pour divers processus industriels, et que l'électricité produite entraîne des émissions carboneutres. Si cette transformation n'est pas engagée d'ici 2035, le Canada risque de ne pas atteindre ses objectifs en matière de changement climatique, à savoir devenir une économie carboneutre d'ici 2050.

Pour déterminer l'instrument ou le mélange d'instruments le plus efficace et le plus approprié qui garantirait que le secteur de la production d'électricité est sur la bonne voie pour réaliser la transformation requise d'ici 2035, le ministère a pris en compte le régime réglementaire fédéral actuel qui affecte le secteur dans le scénario de référence (statu quo), y compris les actions non réglementaires. Il a été déterminé que le régime réglementaire fédéral actuel ne garantit pas que le secteur atteindrait la transformation requise d'ici 2035 et que, par conséquent, une réglementation fédérale est nécessaire. Un résumé de cette évaluation est présenté ci-dessous :

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Scénario de référence / aucun nouveau contrôle

L'approche du scénario de référence implique le maintien des restrictions existantes sur les émissions de l'électricité produite à partir du charbon, telles que définies dans le *Règlement sur la réduction des émissions de dioxyde de carbone — secteur de l'électricité thermique au charbon*, qui fixe généralement une norme de rendement de 420 t/GWh. En outre, l'approche du scénario de référence implique le maintien des restrictions existantes sur les émissions de la production d'électricité à partir de gaz naturel définies dans le *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel*. Celui-ci fixe une norme de rendement de 420 t/GWh pour les chaudières à gaz naturel ou les moteurs à combustion de 150 MW et plus, et une norme de rendement de 550 t/GWh pour les moteurs à combustion de moins de 150 MW.

À partir de 2030, la capacité de production d'électricité à partir de combustibles gazeux qui répond à des critères précis et qui a été mise en place le 1er janvier 2021 ou après cette date, qu'il s'agisse d'une installation existante ou d'une nouvelle installation, serait entièrement exposée au prix du carbone. Toute capacité de production d'électricité existant avant 2021 ne serait soumise au prix du carbone que pour la partie des émissions de GES dépassant une norme de rendement de 370 t/GWh. Dans le scénario de référence, la production au gaz naturel sans dispositif de réduction des émissions, ainsi que les GES associés, devrait augmenter dans les années à venir, à mesure que davantage de technologies électriques seront mises en œuvre (par exemple, le transport électrique) au Canada. Cela limiterait la capacité du Canada à atteindre la carboneutralité dans l'ensemble de l'économie d'ici 2050. La plupart des installations de production d'électricité sont soumises à la tarification de la pollution par le carbone en vertu du *Règlement sur le système de tarification fondé sur le rendement* (RSTFR), ou en vertu de systèmes provinciaux ou territoriaux qui satisfont au critère de référence fédéral (c'est-à-dire le critère national de rigueur minimale que tous les systèmes de tarification du carbone au Canada doivent respecter). En vertu du RSTFR, les installations de production d'électricité couvertes par le système fédéral doivent fournir une compensation pour les émissions de GES qui dépassent la limite d'émissions de l'installation. La compensation peut se faire en payant la redevance sur les émissions excédentaires (65 $/tonne de CO_2e en 2023, puis 170 $/tonne de CO_2e en 2030) ou en fournissant une unité de conformité (crédit excédentaire, crédit compensatoire ou crédit compensatoire provincial reconnu) pour chaque tonne d'émissions dépassant leur limite. Si les émissions sont inférieures à leur limite, les installations reçoivent des crédits excédentaires pour la quantité entre les émissions réelles et la limite d'émissions, qui peuvent être vendus ou mis en réserve pour satisfaire aux obligations de conformité futures.

Dans le cadre du RSTFR, les limites d'émissions sont calculées en multipliant la production d'une installation par la norme de rendement associée à l'activité, qui peut être considérée comme une allocation gratuite. La production d'électricité est soumise à différentes normes basées sur la production en fonction du type de combustible. Pour les combustibles solides, la norme de rendement a commencé à 800 t/GWh en 2019, et diminuera jusqu'à 370 t/GWh en 2030. Pour les combustibles liquides, la norme de rendement est de 500 t/GWh et pour les combustibles gazeux, la norme de rendement est de 370 t/GWh. En outre, les installations de production d'électricité alimentée par les combustibles gazeux qui commencent à produire de l'électricité le 1er janvier 2021 ou après cette date et qui répondent à certaines exigences en matière de taille et de conception ont une norme de rendement de 370 t/GWh en 2021, norme qui diminue jusqu'à 0 t/GWh en 2030. Cela signifie qu'en 2030, les nouvelles installations de production d'électricité alimentées par les combustibles gazeux ne bénéficieront d'aucune allocation gratuite et devront donc payer 100 % des émissions de GES émises par l'installation. La modélisation effectuée par le ministère indique que les émissions du secteur de l'électricité ne diminueraient pas

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suffisamment pour atteindre les objectifs du projet de règlement et pourraient en fait augmenter de manière significative au cours des prochaines décennies.

Le gouvernement du Canada dispose de programmes d'investissement dans les infrastructures de base qui se concentrent sur l'infrastructure de réseaux d'énergie propre, avec des investissements combinés totaux de près de 10 milliards de dollars. Cela comprend des programmes tels que le Programme des énergies renouvelables intelligentes et de trajectoires d'électrification (ÉRITE) de Ressources naturelles Canada, un programme de 1,57 milliard de dollars, dont 600 millions de dollars annoncés dans le budget 2022, qui fournit un soutien aux projets d'énergie renouvelable intelligente et de modernisation du réseau électrique, y compris les projets qui soutiennent le renforcement des capacités. De décembre 2021 à février 2023, le ÉRITE a fourni un financement d'environ 164,5 millions de dollars[27]. Dans le budget 2023, le gouvernement du Canada a annoncé une augmentation du financement de 3 milliards de dollars pour le ÉRITE.

Le gouvernement du Canada fournit un financement à faible taux d'intérêt aux projets d'électricité propre par le biais de divers mécanismes, y compris les investissements et le financement de la Banque de l'infrastructure du Canada (BIC) et du Fonds stratégique pour l'innovation, ainsi que des incitations fiscales fédérales. Ces initiatives totalisent plus de 20 milliards de dollars. Cela comprend le Fonds de Croissance du Canada Inc. (15 milliards de dollars pour financer des investissements à l'appui d'une économie à zéro émission de GES) et le financement du secteur de l'énergie propre annoncé dans le budget 2023 par l'intermédiaire de la Banque de l'infrastructure du Canada (10 milliards de dollars dans le cadre du domaine prioritaire de l'énergie propre pour la construction d'importantes centrales électriques propres).

Le gouvernement du Canada s'attend à ce que ces programmes d'investissement soient d'une importance cruciale, car ils fonctionneraient en tandem avec le projet de règlement pour aider à atteindre les objectifs du Canada en transformant le réseau électrique avant 2035 pour aider à atteindre une économie carboneutre d'ici 2050.

Utiliser le système de tarification du carbone pour réduire les émissions du secteur de l'électricité

Actuellement, les critères nationaux minimaux de rigueur pour les systèmes de tarification du carbone (la référence fédérale) exigent que les systèmes explicites basés sur le prix du carbone, tels que le système fédéral de tarification basé sur la production, soient conçus de manière à ce que le signal de prix marginal soit égal au prix de référence, mais permettent aux systèmes d'appliquer des coûts moyens du carbone plus faibles aux installations industrielles afin d'atténuer les risques de fuite de carbone et de compétitivité qui peuvent survenir en raison de la tarification du carbone. Pour ce faire, les systèmes exigent des installations qu'elles paient le prix du carbone pour les émissions qui dépassent une limite d'émission et délivrent des crédits négociables aux installations qui émettent moins que cette limite. Cette approche crée un signal de prix au prix de référence pour chaque tonne d'émissions, mais comme les installations n'ont pas à payer le prix du carbone pour toutes leurs émissions, elle réduit les coûts moyens du carbone et le risque de fuite de carbone et d'effets négatifs sur la compétitivité.

[27] Source: Projets financés à ce jour - Programme des énergies renouvelables intelligentes et de trajectoires d'électrification (canada.ca)

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La réduction des émissions de GES provenant du secteur de l'électricité pourrait être obtenue en veillant à ce qu'un prix du carbone élevé soit payé pour chaque tonne d'émissions de l'électricité. Si les producteurs d'électricité devaient payer le prix du carbone pour chaque tonne d'émissions, leur coût moyen du carbone augmenterait. Le ministère a effectué plusieurs exercices de modélisation et a déterminé qu'un prix du carbone de 170 $/tonne appliqué à chaque tonne d'émissions du secteur de l'électricité ne permettrait pas au secteur de se rapprocher suffisamment de l'objectif de carboneutralité d'ici 2035. En outre, dans un scénario de modélisation à forte demande, un prix du carbone de 170 $/tonne n'a pas été jugé suffisamment élevé pour rendre les technologies de production d'électricité peu émettrices nettement plus compétitives que les technologies émettrices ; si les technologies de production peu et non émettrices ne sont pas les options les plus compétitives en termes de coûts, on s'attend à ce que les émissions du secteur augmentent. Par conséquent, si le fait d'exiger que le prix du carbone soit payé pour chaque tonne d'émissions provenant de la production d'électricité devait permettre d'obtenir des réductions d'émissions supplémentaires, cela ne permettrait pas d'obtenir les réductions nécessaires pour atteindre l'objectif de carboneutralité d'ici 2035.

En outre, les systèmes de tarification de la pollution par le carbone au Canada sont un outil économique qui incite fortement à réduire les émissions de la manière la plus rentable possible pour toutes les sources d'émissions qu'il couvre. Cette forte incitation est due à sa conception, qui ne fixe pas de limites spécifiques pour les émissions des différents secteurs. Elles ne garantissent pas un certain niveau de réduction dans un secteur spécifique et ne sont donc pas l'outil approprié pour garantir la réalisation de l'objectif d'un secteur de l'électricité carboneutre.

En l'absence de norme réglementée, il sera probablement plus économique pour les services publics i) de continuer à utiliser du gaz naturel sans dispositif de réduction des émissions pour produire une énergie de base fiable et de payer un prix plus élevé pour la pollution, ou ii) d'acquérir et de transférer des crédits excédentaires ou compensatoires. En l'absence d'autres contraintes, c'est le choix que feraient probablement les producteurs plutôt que de transformer leur équipement de production pour produire de l'électricité fiable à émissions quasi nulles grâce à des solutions technologiques telles que l'énergie éolienne ou solaire associée au stockage de l'énergie ou le gaz naturel associé à une technologie moderne de captage et de stockage du carbone (CSC). Dans l'ensemble, l'analyse du ministère indique que le fait d'exiger des producteurs d'électricité qu'ils paient un prix du carbone élevé sur toutes leurs émissions ne serait pas suffisant en soi pour garantir que le secteur de l'électricité réalise d'ici 2035 la transformation nécessaire pour soutenir l'objectif du Canada en matière de changement climatique, à savoir devenir une économie carboneutre d'ici 2050.

L'approche réglementaire proposée

La réduction des émissions de GES pour parvenir à un réseau électrique carboneutre et pour soutenir une économie carboneutre d'ici 2050 nécessiterait une transition planifiée et permanente vers l'abandon de la production d'électricité à partir de combustibles fossiles. Le projet de règlement s'appuie sur le cadre réglementaire existant pour le secteur de l'électricité afin de poursuivre la transition permanente de la production d'électricité à partir de combustibles fossiles vers des sources de production peu ou non émettrices. Des progrès significatifs dans cette direction pourraient être accomplis grâce à l'application de normes de rendement strictes à l'horizon 2035. La norme réglementaire exigerait la production d'électricité au gaz naturel à avoir des dispositifs de réduction des émissions afin de fournir une production de base. Cette approche fournirait également un point de référence réglementaire clair qui définirait ce qui constitue de l'électricité propre, tout en fournissant aux producteurs d'électricité des délais suffisants pour adapter leurs plans d'investissement. Toutefois, étant donné que la norme de

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rendement proposée serait fixée à une valeur non nulle et que l'approche réglementaire proposée inclurait plusieurs flexibilités en matière de conformité, le secteur de la production d'électricité continuerait à avoir de faibles niveaux d'émissions résiduelles. Des actions supplémentaires seraient nécessaires avant que le secteur de la production d'électricité ne parvienne à la carboneutralité.

Dans le cadre de l'approche du projet de règlement, le ministère a envisagé plusieurs options pour les paramètres clés, notamment la norme de rendement en matière d'émissions, les marges de manœuvre en matière de conformité, le seuil de capacité, la couverture de la production industrielle et la fin de la vie réglementaire. Les effets de la variation de ces paramètres sont évalués dans la section du REIR consacrée à l'analyse de sensibilité.

Analyse réglementaire

Avantages et coûts

Sources de données et paramètres analytiques

Une analyse coûts-avantages (ACA) est réalisée pour déterminer les répercussions supplémentaires (coûts et avantages) d'un scénario réglementaire par rapport à ceux d'un scénario de référence. Pour ce projet de règlement, l'ACA compare les répercussions d'un scénario avec le projet de règlement à ceux d'un scénario sans celui-ci. Le principal facteur de répercussions différentielles pour le projet de règlement est la composition du réseau électrique modélisé dans le scénario de référence par rapport à celui modélisé dans le scénario réglementaire. Dans l'ACA, la composition du réseau électrique fait référence à l'ensemble des infrastructures qui composent le réseau électrique (p. ex. production sans émission, production émettrice avec dispositif de réduction des émissions, production émettrice, stockage, lignes de transmission reliant les réseaux de services publics d'électricité), aux spécifications techniques de ces infrastructures (p. ex. capacité, production, utilisation de combustibles, intensité des émissions, facteurs d'opération et de maintenance) et à l'utilisation de ces infrastructures (p. ex. réseau électrique seulement, production, production industrielle, production d'appoint ou d'urgence). En vertu du projet de règlement, la composition du réseau électrique du Canada évoluerait vers des sources de production d'électricité peu ou non émettrices plus rapidement et dans une plus grande mesure que dans le scénario de référence, et il y aurait plus d'investissement dans le stockage et la transmission.

La composition du réseau électrique et les facteurs connexes qui pourraient être réalisés dans le cadre d'un scénario de référence par rapport à un scénario réglementaire ont été projetés par deux modèles ministériels. Le premier modèle, NextGrid, est un modèle d'expansion de la capacité qui identifie les décisions optimales d'investissement et d'exploitation dans le réseau électrique canadien, en minimisant les coûts à l'échelle du réseau (national) afin de satisfaire la demande, sous réserve de plusieurs contraintes telles que les paramètres des politiques, la fiabilité du réseau et la disponibilité des ressources (ex. : contraintes géologiques). Le deuxième modèle est le modèle Énergie, émissions et économie du Canada (E3MC), qui comprend lui-même deux composantes. La première composante du modèle E3MC est Énergie 2020 (E2020), un modèle nord-américain intégré, multirégional et multisectoriel qui simule l'offre, le prix et la demande de tous les combustibles. E2020 estime la production et les prix de l'énergie pour chaque secteur sur les marchés réglementés et non réglementés, et simule la manière dont les prix de l'énergie et les mesures gouvernementales peuvent affecter les choix des consommateurs et des entreprises lorsqu'ils achètent et utilisent de l'énergie. Les résultats d'E2020 comprennent des changements dans la consommation d'énergie, les prix de l'énergie, les émissions de gaz à effet de serre, les émissions de polluants atmosphériques, les coûts d'investissement

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et les économies possibles grâce aux mesures, qui sont utilisées pour identifier les effets directs des mesures visant à réduire les émissions de gaz à effet de serre. Les économies et les investissements résultant d'E2020 sont ensuite utilisés comme intrants dans la deuxième composante d'E3MC, le modèle Informetrica (TIM). Le TIM est utilisé pour examiner les décisions de consommation, d'investissement, de production et de commerce dans l'ensemble de l'économie. Il saisit les interactions entre les industries, ainsi que les implications des changements dans les prix à la production, les prix finaux relatifs et les revenus. Il tient également compte des soldes budgétaires des gouvernements, des flux monétaires et des taux d'intérêt et de change. TIM projette les répercussions directes sur la demande finale, la production, l'emploi, la formation des prix et le revenu sectoriel de l'économie qui résultent des différents choix politiques. Ceux-ci permettent à leur tour d'estimer l'effet des politiques en lien avec le changement climatique et des répercussions connexes sur l'économie nationale.[28]

NextGrid et E3MC sont capables de modéliser la composition des réseaux électriques au Canada jusqu'en 2050 et fondent leurs résultats sur des algorithmes d'optimisation et des contraintes qui sont distinctes pour chaque modèle, en utilisant des données provenant d'une multitude de sources, y compris Statistique Canada et une collaboration continue avec les provinces et les services publics. Dans la mesure du possible et le cas échéant, les hypothèses sous-jacentes et l'application du projet de règlement ont été harmonisées entre E3MC et NextGrid afin de produire des résultats à partir des deux modèles qui peuvent être utilisés en tandem tout au long de l'ACA. Dans l'ACA, la composition du réseau électrique dans le scénario de référence a été modélisée par E3MC, tandis que la composition du réseau électrique dans le scénario de référence a été modélisée par NextGrid et E3MC. Plus précisément, NextGrid a modélisé les décisions que peuvent prendre les groupes existants qui ne respectent pas la limite d'intensité des émissions de CO_2 à partir de 2035 (c.-à-d. mise hors service anticipée, mise à niveau avec systèmes de CSC, changement du régime d'exploitation pour opérer selon la flexibilité basée sur les heures d'opérations et la masse d'émissions), tandis que E3MC a modélisé les décisions que peuvent prendre tous les autres groupes. NextGrid a également été utilisé pour modéliser et chiffrer les nouvelles lignes de transmission interprovinciales qui pourraient être construites dans le cadre du scénario réglementaire. Hormis ces lignes de transmissions, tous les autres coûts du réseau électrique et de l'ensemble de l'économie utilisés dans l'ACA ont été calculés par E3MC. L'ACA utilise les résultats d'E3MC et de NextGrid pour présenter une distribution des impacts jugés attribuables au projet de règlement, tout en reconnaissant une variété de changements économiques et environnementaux externes qui peuvent se produire au cours de la période d'analyse en utilisant des hypothèses conservatrices le cas échéant et en testant des paramètres alternatifs dans l'analyse de sensibilité.

Il est important de noter que le projet de règlement ne prescrit aucune voie de conformité particulière pour un groupe particulier qui ne respecte pas la limite d'intensité des émissions de CO_2 à partir de 2035. Tous les résultats présentés dans le résumé de l'étude d'impact de la réglementation représentent un scénario modélisé indiquant ce qui pourrait se produire en réponse au projet de règlement sur la base de contraintes et d'hypothèses raisonnables (c'est-à-dire la modélisation du cas central). Ce scénario central ne représente pas la seule voie que le secteur de la production d'électricité pourrait emprunter pour se conformer aux exigences réglementaires et ne doit pas être interprété comme étant plus probable que d'autres voies potentielles. De même, il est important de reconnaître le vaste degré d'incertitude lors de la modélisation des changements structurels associés à la décarbonisation de l'économie sur une longue période. Un large éventail de résultats est finalement possible, qui pourrait être déterminé par des

[28] La méthodologie d'élaboration des scénarios d'émissions dans E3MC est décrite à l'annexe 7 du chapitre 5 de la 8e communication nationale et 5e rapport biennal du Canada (2022), et les principales sources de données utilisées dans le modèle sont présentées dans le rapport de 2023 sur les indicateurs canadiens de durabilité de l'environnement.

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développements technologiques nouveaux ou imprévus, ainsi que par des facteurs macroéconomiques, des changements démographiques et des paysages politiques à tous les niveaux de gouvernement, qui pourraient modifier fondamentalement la modélisation de base.

En vertu du projet de règlement, certains coûts administratifs pour l'industrie commenceraient en 2024 dès l'enregistrement anticipé du règlement. Les résultats d'E3MC indiquent que les changements apportés à la composition du réseau électrique du Canada et les changements associés aux coûts du réseau pourraient commencer dès 2026 en prévision de l'entrée en vigueur de la limite d'intensité des émissions de CO_2 à partir de 2035. Pour cette raison, et compte tenu de l'objectif du Canada de parvenir à des émissions nettes nulles d'ici 2050, la période d'analyse choisie pour l'ACA s'étend de 2024 à 2050 (soit une période de 27 ans). Sauf indication contraire, tous les coûts et avantages monétaires sont présentés en dollars constants de 2022, actualisés à l'année de référence 2023 à un taux d'actualisation de 2 %. Il s'agit du taux d'actualisation à court terme de Ramsey actuellement utilisé par le gouvernement du Canada pour monétiser les réductions de GES, sur la base de l'état le plus récent de la science du climat (de plus amples informations sur cette approche sont présentées dans la sous-section sur les avantages). Dans tous les tableaux qui suivent, les totaux peuvent ne pas correspondre à la somme des composantes en raison des arrondissements.

Principales hypothèses de modélisation de l'ACA

Certains groupes de production d'électricité produisent de l'électricité à des fins industrielles dans les limites de l'installation (c'est-à-dire au sein d'une installation industrielle). Un sous-ensemble de ces groupes industriels de production vend une partie de l'électricité qu'il produit à un réseau électrique réglementé par la NERC. En vertu du projet de règlement, tout groupe d'une capacité supérieure ou égale à 25 MW qui est connecté à un réseau électrique réglementé par la NERC et qui a un solde exportateur d'électricité supérieur à zéro gigawattheure à partir de 2035 (ou de l'année de conformité pertinente) doit se conformer à la norme rendement de 30 t/GWh d'émissions de CO_2 sauf s'il remplit toutes les conditions liées à l'une des exceptions. La modélisation de l'ACA suppose que tous les groupes de production industrielle qui ont un solde exportateur d'électricité vers un réseau électrique supérieur à zéro gigawattheure dans le scénario de référence entreprendraient les investissements liés à la réduction des émissions nécessaires pour continuer à vendre une partie de l'électricité qu'elles produisent au réseau électrique dans le scénario réglementaire. Par extension, la proportion d'électricité que ces groupes industriels produisent pour une utilisation dans les limites de celle-ci respecterait également la norme rendement des émissions de CO_2. Dans l'ACA, les réductions d'émissions attribuables à la production vendue au réseau électrique (par les compagnies d'électricité et les groupes de production industrielle) sont considérées comme des bénéfices principaux, tandis que les réductions d'émissions attribuables à la production utilisée dans les limites de l'installation sont considérées comme des co-bénéfices. En revanche, l'ACA ne fait aucune distinction entre les coûts encourus par les compagnies d'électricité et ceux encourus par la production industrielle. En reconnaissance du fait que tout investissement qui serait entrepris afin de respecter la norme rendement des émissions de CO_2 est considéré comme un coût direct du projet de règlement, quel que soit l'endroit où l'électricité produite est utilisée. Les groupes industriels qui ne sont pas connectés à un réseau électrique réglementé par la NERC et qui produisent uniquement de l'électricité pour une utilisation dans les limites de celle-ci ne sont pas soumis au projet de règlement et sont donc hors du champ d'application de l'ACA.

Aux fins de l'analyse, le ministère a modélisé dans le scénario de référence les lignes de transport interprovinciales (ou interconnexions), y compris celles qui n'ont pas encore été construites (par exemple, la boucle de l'Atlantique). Les interconnexions régionales sont considérées comme une stratégie de

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conformité clé pour les provinces tributaires du charbon afin de satisfaire aux exigences du Règlement sur la réduction des émissions de dioxyde de carbone — secteur de l'électricité thermique , tel qu'il a été modifié en 2018, et ne sont pas considérées comme des éléments supplémentaires liés au projet de règlement. La modélisation indique que les interconnexions régionales dans la région de l'Atlantique constituent l'option la moins coûteuse pour se conformer au projet de règlement.

Le scénario de référence inclut également les politiques et programmes de financement fédéraux liés aux investissements dans l'infrastructure du réseau électrique. Plus précisément, le scénario de référence tient compte d'une abstraction du crédit d'impôt à l'investissement (CII[29]) pour les technologies propres qui a été annoncé dans l'exposé économique de l'automne 2022, en réduisant le coût marginal du capital de la construction de nouvelles installations (par MW) de technologies admissibles de 30 % en 2023 jusqu'en 2031, puis en supprimant les crédits de façon linéaire de 2032 à 2035. Le CII modélisé affecte le coût relatif auquel l'industrie doit faire face pour construire des technologies du réseau électrique non émettrices qualifiées par rapport aux technologies du réseau électrique émettrices, augmentant ainsi l'attractivité des investissements dans la capacité non émettrice dans le scénario de référence par rapport à ce qu'elle a été historiquement. Le CII modélisé a été appliqué au nucléaire, à l'hydroélectricité par pompage, à la petite hydroélectricité, à l'éolien terrestre, à l'éolien en mer, au solaire photovoltaïque, à l'énergie houlomotrice et au stockage, mais pas aux technologies émettrices qui mettent en œuvre un système de captage et de stockage du carbone. La modélisation du cas central n'a pas intégré l'ensemble des aides fédérales qui seront mises à la disposition du secteur de la production d'électricité au Canada. Au fur et à mesure que les détails concernant le nouveau CII pour l'électricité propre et son application deviennent disponibles, ainsi que les nouvelles mesures supplémentaires annoncées dans le budget 2023, la conception finale du CII pour les technologies propres, le CII pour le CCS et toute décision de financement fédéral future (p. ex., Fond stratégique pour l'innovation, Initiative Accélérateur net zéro), la modélisation future du scénario central serait ajustée pour s'aligner sur ce traitement. Ces décisions de financement fédéral devraient réduire l'ampleur des impacts différentiels évalués pour le projet de règlement (c'est-à-dire des coûts et des avantages moindres), étant donné que des mesures supplémentaires visant à réduire les émissions de GES dans le secteur de la production d'électricité devraient être prises dans le cadre du scénario de référence.

Les tarifs en Nouvelle-Écosse et au Nouveau-Brunswick devraient augmenter à l'avenir dans le cadre du scénario de référence. En plus des mesures incluses dans l'Énoncé économique de l'automne 2022 et le budget 2023 qui soutiennent la décarbonisation de l'électricité, le gouvernement fédéral a offert un financement pour construire des lignes de transmission qui contribueront aux efforts visant à atténuer les impacts sur les tarifs d'électricité dans la région. La réduction des augmentations de tarifs prévues dans le scénario de base diminue également l'impact global du projet de règlement sur les tarifs.

Du point de vue de l'analyse coûts-avantages, il convient de noter que toute dépense publique relative aux incitatifs financiers fédéraux constituerait un transfert de coûts de l'industrie (et, par extension, des consommateurs d'électricité) vers l'assiette fiscale générale. La modélisation du cas central tient compte de l'absorption progressive du financement fédéral en projetant d'abord la combinaison de systèmes électriques qui serait construite dans les scénarios de référence et de réglementation avec le CII

[29] Le CII publié dans l'énoncé économique de 2022 incitera également les entreprises à créer des emplois. Celles qui respectent certaines conditions de travail pourront bénéficier de l'intégralité du crédit de 30 % au titre du CII, tandis que celles qui ne le respectent pas ne pourront prétendre qu'à un crédit de 20 %. Les conditions de travail comprennent le versement des salaires en vigueur sur la base des conditions du marché du travail local et la création d'opportunités de formation en apprentissage.

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modélisé en place, puis en déterminant les dépenses publiques supplémentaires associées à ces investissements.

Composition du réseau électrique

La composition du réseau électrique canadien peut être caractérisée sur deux bases : la capacité et la production. La capacité électrique représente la capacité maximale d'un groupe à produire de l'électricité (exprimée en MW), tandis que la production électrique est la quantité réelle d'électricité produite par un groupe sur une période donnée (exprimée en GWh). Les groupes de production ne fonctionnent pas toujours à plein rendement. Par exemple, un groupe d'éolienne produirait en dessous de sa capacité lorsque la vitesse du vent est faible et un groupe d'appoint ne produirait à plein rendement que lorsque cela est nécessaire pour la fiabilité. La modélisation d'E3MC indique que le secteur des services publics d'électricité du Canada (à l'exclusion de tout groupe de production industrielle) adopterait les caractéristiques de capacité suivantes dans le scénario de référence (tableau 4) par rapport au scénario réglementaire (tableau 5) :

Tableau 4. Composition du réseau électrique par type de technologie (en fonction de la capacité), scénario de référence

Type de technologie	2025	2030	2035	2040	2045	2050
Émettrice*	17,9 %	16,4 %	14,1 %	13,4 %	12,9 %	12,6 %
Émettrice avec CSC	0,1 %	0,1 %	0,3 %	0,4 %	0,5 %	0,5 %
Nucléaire	8,8 %	6,1 %	5,1 %	4,8 %	4,6 %	4,3 %
Hydroélectricité	53,1 %	43,1 %	39,2 %	37,7 %	37,0 %	36,7 %
Autres non émettrices**	20,1 %	34,3 %	41,3 %	43,7 %	45,1 %	45,9 %
Capacité totale (%)	100 %	100 %	100 %	100 %	100 %	100 %
Capacité totale (MW)	149 244	183 907	220 858	234 536	243 420	258 442
Stockage (MW)	2 701	4 877	6 607	7 285	7 832	9 021

* Pour les tableaux 4 à 7, « Émettrice » fait référence aux technologies suivantes : TCPG, CCPG, petit CCPG, PG à la vapeur, Charbon, Biomasse et déchet, ce qui peut être différent de ce qui constitue une technologie émettrice dans le RIN.
* Pour les tableaux 4 à 7, « Autres non émettrices » fait référence aux technologies suivantes : éolien terrestre, éolien en mer, PV solaire, géothermie et turbine marémotrice

Tableau 5. Composition du réseau électrique par type de technologie (en fonction de la capacité), scénario réglementaire

Type de technologie	2025	2030	2035	2040	2045	2050
Émettrice	17,9 %	15,6 %	9,0 %	8,0 %	6,7 %	6,5 %
Émettrice avec CSC	0,1 %	0,9 %	3,8 %	4,2 %	4,9 %	4,8 %
Nucléaire	8,8 %	6,2 %	5,4 %	5,0 %	5,1 %	5,1 %
Hydroélectricité	53,1 %	43,1 %	39,6 %	38,0 %	37,6 %	37,6 %
Autres non émettrices	20,1 %	34,3 %	42,2 %	44,8 %	45,6 %	46,0 %
Capacité totale (%)	100 %	100 %	100 %	100 %	100 %	100 %
Capacité totale (MW)	149 244	183 725	219 876	240 008	247 801	260 301

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Stockage (MW)	2 701	5 052	6 887	7 745	8 658	9 931

De même, E3MC suggère que le secteur des services publics d'électricité du Canada (à l'exclusion de tout groupe de production industrielle) adopterait les caractéristiques de production suivantes dans le scénario de référence (tableau 6) par rapport au scénario réglementaire (tableau 7) :

Tableau 6. Composition du réseau électrique par type de technologie (base de production), scénario de référence

Type de technologie	2025	2030	2035	2040	2045	2050
Émettrice	14,3 %	9,9 %	7,1 %	6,9 %	6,3 %	6,2 %*
Émettrice avec CSC	0,1 %	0,1 %	0,1 %	0,1 %	0,1 %	0,1 %
Nucléaire	10,9 %	9,7 %	9,7 %	9,0 %	8,7 %	8,3 %
Hydroélectricité	62,0 %	56,4 %	52,9 %	51,5 %	50,7 %	49,9 %
Autres non émettrices	12,6 %	23,8 %	30,2 %	32,5 %	34,1 %	35,6 %
Production totale (%)	100 %	100 %	100 %	100 %	100 %	100 %
Production totale (GWh)	620 300	685 808	772 314	807 363	836 810	885 514

* Sur cette proportion, 9 % de la production d'émissions en 2050 est attribuable à la biomasse et aux déchets.

Tableau 7. Composition du réseau électrique par type de technologie (base de production), scénario réglementaire

Type de technologie	2025	2030	2035	2040	2045	2050
Émettrice	14,3 %	9,7 %	3,8 %	1,7 %	0,8 %	1,1 %*
Émettrice avec CSC	0,1 %	0,3 %	1,1 %	0,8 %	1,2 %	1,1 %
Nucléaire	10,9 %	9,7 %	10,1 %	9,5 %	9,2 %	9,3 %
Hydroélectricité	62,0 %	56,4 %	54,0 %	53,5 %	53,5 %	52,5 %
Autres non émettrices	12,6 %	23,8 %	31,1 %	34,5 %	35,3 %	36,1 %
Production totale (%)	100 %	100 %	100 %	100 %	100 %	100 %
Production totale (GWh)	620 300	685 689	774 404	810 726	838 254	886 766

* Sur cette proportion, 42 % de la production d'émissions en 2050 est attribuable à la biomasse et aux déchets.

En l'absence du projet de règlement (tableau 6), il aurait été anticipé que le réseau électrique canadien réduise la production provenant de technologie émettrice de 14,3 % en 2025 à 6,2 % en 2050 et qu'il augmente la production provenant de technologie non émettrice de 85,5 % en 2025 à 93,7 % en 2050. En revanche, en vertu du projet de règlement (tableau 7), il est anticipé que le réseau électrique canadien réduise la production provenant de technologie émettrice de 14,3 % en 2025 à 1,1 % en 2050 et augmente la production provenant de technologie non émettrice de 85,5 % en 2025 à 97,9 % en 2050.

Avantages

Le projet de règlement réduirait la quantité de GES émis par les groupes de production d'électricité au Canada, sous forme de dioxyde de carbone (CO_2), de méthane (CH_4) et d'oxyde nitreux (N_2O), le CO_2 étant le plus important. La réduction des émissions de ces gaz permettrait d'éviter les dommages causés

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par le changement climatique à l'échelle mondiale. Le projet de règlement réduirait également la quantité de polluants atmosphériques émis par les groupes de production d'électricité, notamment les oxydes d'azote (NO_X), les oxydes de soufre (SO_X), les particules primaires d'une largeur inférieure à 2,5 microns ($PM_{2.5}$) et le mercure (Hg). La réduction de ces polluants atmosphériques pourrait entraîner une amélioration de la qualité de l'air au niveau local, en fonction des caractéristiques géographiques et météorologiques des sites d'émission, ce qui pourrait avoir des effets bénéfiques sur la santé et l'environnement.

Étant donné que les sources de production d'électricité émettrices sont remplacées par des sources peu ou non émettrices, le projet de règlement permettrait également au secteur de l'électricité de réaliser des économies au fil du temps, sous la forme d'une utilisation évitée des combustibles, d'opération et de maintenance, et de remise en état.

Chacun de ces avantages est décrit en détail dans les sous-sections ci-dessous.

Dommages évités au niveau mondial en raison du changement climatique

En utilisant les résultats du modèle E3MC, l'ACA estime que le projet de règlement entraînerait la réduction de 272 Mt de GES (exprimés en CO_2e) provenant de la production d'électricité vendue à un réseau électrique réglementé par la NERC, ainsi que la réduction de 70 Mt de GES provenant de la production d'électricité utilisée dans les limites de l'installation, pour des réductions totales de près de 342 Mt au cours de la période d'analyse de 27 ans (2024 à 2050) (tableau 8).

Tableau 8. Réductions supplémentaires de GES (exprimées en kilotonnes de CO_2 e*)

Description	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annuelle (n=27)
CO_2 (réseau électrique)	-1 112	13 024	75 308	87 058	93 811	268 088	9 929
CH_4 (réseau électrique)	-5	124	643	577	568	1 907	71
N_2O (réseau électrique)	-12	83	539	566	589	1 765	65
CO_2 (dans les limites de l'installation)	2 293	5 508	20 492	20 689	20 544	69 527	2 575
CH_4 (dans les limites de l'installation)	1	31	126	54	26	238	9
N_2O (dans les limites de l'installation)	12	28	106	104	101	350	13
Principaux avantages : Réductions de GES attribuables à la production d'électricité vendue au réseau électrique**.	-1 129	13 231	76 490	88 201	94 968	271 761	10 065
Co-bénéfices : Réductions de GES attribuables à la production d'électricité utilisée dans les limites de l'installation***.	2 306	5 567	20 725	20 847	20 671	70 116	2 597
Réductions totales de GES	1 177	18 798	97 215	109 048	115 640	341 877	12 662

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* CH_4 et N_2O ont été convertis en CO_2 e en utilisant des facteurs de potentiel de réchauffement planétaire de 25 et 298, respectivement.
** Ce sous-total représente la somme du CO_2 (réseau électrique), du CH_4 (réseau électrique) et du N_2O (réseau électrique).
*** Ce sous-total représente la somme de CO_2 (dans les limites de l'installation), CH_4 (dans les limites de l'installation) et N_2O (dans les limites de l'installation).

Les dommages évités au niveau mondial provenant des changements climatiques associés à ces réductions de GES peuvent être monétisés à l'aide d'estimations du coût social de chaque polluant. En novembre 2022, l'Agence américaine de protection de l'environnement (US EPA) a publié une version préliminaire *(Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances)*, dans lequel les méthodologies et les valeurs du coût social (CS) ont été mises à jour et présentées pour le CO_2, le CH_4 et le N_2O. Au cours du mois d'avril 2023, le ministère a publié un *projet d'orientation sur les CS pour le Canada*, en accord avec les valeurs des CS-GES proposées par l'EPA. Un sous-ensemble de valeurs canadiennes CS-GES tirées de ce document d'orientation est présenté dans le tableau 9.

Tableau 9. Valeurs annuelles CS-CO_2, CS-CH_4 et CS-N_2O pour certaines années (2021 CAD, $/tonne, actualisé à l'année d'indice pertinente à 2 %)*.

Année de l'indice	CS-CO_2	CS-CH_4	CS-N_2O
2020	247 $	2 107 $	69 230 $
2025	271 $	2 589 $	77 066 $
2030	294 $	3 073 $	84 903 $
2035	317 $	3 634 $	92 894 $
2040	341 $	4 194 $	100 886 $
2045	367 $	4 803 $	109 902 $
2050	394 $	5 410 $	118 919 $

* Les valeurs CS pour CH_4 et N_2O intègrent leur propre concept de potentiel de réchauffement planétaire dans les calculs. Ainsi, pour utiliser ces valeurs CS dans l'ACA, elles doivent être multipliées par les réductions de tonnage de CH_4 et de N_2O, et non par les réductions de tonnage de ces polluants exprimées en CO_2e.

Les valeurs canadiennes du CS-GES du tableau 9 reflètent l'état le plus récent de la science du climat. Comme l'explique la version préliminaire du rapport de l'EPA, les valeurs CS-GHG actualisées sont le fruit de l'interaction de quatre modules : socio-économique et émissions, climatique, dommages, et actualisation. Le module socio-économique et émissions repose sur un nouvel ensemble de projections probabilistes de la population, des revenus et des émissions de GES élaborées dans le cadre de l'initiative « Resources for the Future Social Cost of Carbon » (coût social du carbone). Le module climatique s'appuie sur le modèle Finite Amplitude Impulse Response (un modèle du système terrestre largement utilisé et recommandé par les « National Academies »), qui saisit les relations entre les émissions de GES, les concentrations atmosphériques de GES et la température moyenne à la surface du globe. Les projections socio-économiques et les résultats du module climatique sont utilisés comme données d'entrée dans le module des dommages pour estimer les dommages futurs monétisés résultant des changements de température. Le module d'actualisation actualise le flux des futurs dommages climatiques en remontant jusqu'à l'année des émissions à l'aide d'un ensemble de taux d'actualisation dynamiques qui comportent une grande part d'incertitude. Comme indiqué dans la version préliminaire du rapport de l'EPA, les modules utilisent des hypothèses méthodologiques prudentes et sont donc susceptibles de sous-estimer les dommages marginaux dus à la pollution par les GES.

L'ACA a converti les valeurs CS-GES canadiennes présentées au tableau 9 en dollars constants de 2022 en utilisant un facteur de conversion de 1,068 98 (dérivé des estimations de l'Indice des prix à la

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consommation dans E3MC), puis a multiplié ces valeurs par les réductions de tonnage de chaque polluant (pas en termes de CO_2e) résumées dans le tableau 8, avant d'actualiser les résultats à l'année de référence 2023 à 2 %. Comme le montre le tableau 10, le projet de règlement permettrait d'éviter plus de 87,5 milliards de dollars de dommages mondiaux causés par les changements climatiques au cours de la période d'analyse de 27 ans, dont 69,45 milliards de dollars seraient attribuables à la production d'électricité vendue au réseau électrique.

Tableau 10. Dommages évités au niveau mondial en raison du changement climatique (millions de dollars)

Description	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)
CO_2 (réseau électrique)	-306	3 477	19 809	22 347	23 440	68 767	3 321
CH_4 (réseau électrique)	-1	15	81	76	76	248	12
N_2O (réseau électrique)	-3	22	140	145	148	453	22
CO_2 (dans les limites de l'installation)	632	1 478	5 392	5 313	5 134	17 949	867
CH_4 (dans les limites de l'installation)	0,1	4	16	7	4	30	1
N_2O (dans les limites de l'installation)	3	7	28	27	26	90	4
Principaux avantages : Avantages en matière de changement climatique attribuables à la production d'électricité vendue au réseau électrique*.	-310	3 514	20 030	22 568	23 665	69 468	3 355
Co-bénéfices : Bénéfices liés au changement climatique attribuable à la production d'électricité utilisée dans les limites de l'installation**.	635	1 489	5 436	5 346	5 163	18 069	873
Total des bénéfices liés au changement climatique	325	5 003	25 466	27 914	28 828	87 537	4 227

* Ce sous-total représente la somme du CO_2 (réseau électrique), du CH_4 (réseau électrique) et du N_2O (réseau électrique).

** Ce sous-total représente la somme de CO_2 (dans les limites de l'installation), CH_4 (dans les limites de l'installation) et N_2O (dans les limites de l'installation).

Comme indiqué dans la description du REIR, une marge de manœuvre serait disponible jusqu'en 2040 pour tout groupe qui met en service un système de CSC, ce qui permettrait à ces groupes de fonctionner jusqu'à 40 t/GWh pendant sept ans ou jusqu'au 31 décembre 2039, selon la première éventualité, à condition que le groupe ait démontré qu'il peut fonctionner à 30 t/GWh ou moins pendant deux périodes déterminées au cours d'une année. La modélisation de l'analyse coûts-avantages part du principe que ces groupes seront en mesure d'atteindre 30 t/GWh d'ici 2035 et ne modélise donc pas l'utilisation de cette flexibilité de conformité. Il convient de noter qu'en fonction de l'utilisation de la flexibilité de conformité par les groupes équipés d'un système de CSC, les réductions de GES et les avantages monétaires associés, les économies de combustible et les coûts variables d'exploitation et d'entretien

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pour ces groupes peuvent être légèrement surestimés dans les années précédant 2040. Toutefois, étant donné que la limite d'intensité des émissions pour les groupes au gaz naturel (la majorité des utilisateurs de CSC) dans le scénario de référence est de 420 à 550 t/GWh selon le *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel*, le fait de passer de ces limites d'intensité des émissions à 40 t/GWh dans le scénario réglementaire (plutôt qu'à 30 t/GWh) pour un nombre limité d'années ne devrait pas réduire de façon significative les avantages marginaux liés aux changements climatiques décrits dans le tableau 10.

Avantages potentiels pour la santé

En utilisant les résultats de l'E3MC, l'ACA estime que le projet de règlement entraînerait des réductions des émissions de polluants atmosphériques provenant de la production d'électricité vendue au réseau électrique ainsi que de la production d'électricité utilisée dans les limites de l'installation. Le tableau 11 présente une répartition de ces réductions par polluant sur la période analytique de 27 ans.

Tableau 11. Réductions supplémentaires des émissions de polluants atmosphériques, par polluant (tonnes)

Description	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annuelle (n=27)
NO_X (réseau électrique)	2 154	25 140	131 363	95 244	90 705	344 605	12 763
SO_X (réseau électrique)	9 277	6 942	42 663	18 965	18 835	96 682	3 581
$P_{2.5}$ (réseau électrique)	44	1 695	8 557	7 858	7 983	26 138	968
Hg (réseau électrique)	0,010 8	0,062 5	0,313 7	0,314 0	0,313 8	1,014 9	0,037 6
NO_X (dans les limites de l'installation)	1 750	3 891	17 863	28 040	27 952	79 496	2 944
SO_X (dans les limites de l'installation)	2 033	2 315	8 186	23 445	23 220	59 200	2 193
$PM_{2.5}$ (dans les limites de l'installation)	14	17	158	544	534	1 268	47
Hg (dans les limites de l'installation)	0,000 3	0,001 1	0,004 2	0,004 3	0,004 3	0,014 2	0,000 5

La répartition de ces réductions supplémentaires d'émissions de polluants atmosphériques par province au cours de la période d'analyse est présentée dans le tableau 12.

Tableau 12. Réductions supplémentaires des émissions de polluants atmosphériques entre 2024 et 2050, par province (en tonnes)*

Province	NO_X	SO_X	$PM_{2.5}$	Hg
T.-N.-L.	591	63	7	0,000 0
Î.-P.-É.	146	185	9,5	0,000 0
N.-É.	27 816	15 039	-224	0,015 4
N.-B.	4 112	29 004	65	0,000 0
Qué.	0,0	0,0	0,0	0,0000
Ont.	225 718	-55	24 412	0,000 1

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Man.	0,0	0,0	0,0	0,0000
Sask.	50 821	68 513	1 900	0,836 3
Alb.	103 914	41 712	1 064	0,015 0
C.-B.	10 978	1 421	172	0,162 1
Yn.	0,6	0	0	0,000 0
T.N.-O.	3,7	0	0,1	0,000 0
Nt.	2	0	0	0,000 0
Total	424 101	155 882	27 406	1,029 0

* E3MC tient compte des émissions de polluants atmosphériques provenant de la production d'électricité ainsi que d'une quantité relativement faible d'émissions de polluants atmosphériques provenant des processus opérationnels, y compris la distribution. Il est possible que certains types de technologie soient associés à des émissions de polluants atmosphériques nulles pour la production d'électricité, mais positives pour les processus opérationnels. Les totaux présentés dans ce tableau représentent la somme des deux sources d'émissions de polluants atmosphériques.

Comme le montre le tableau 12, l'Alberta, la Saskatchewan, l'Ontario, la Nouvelle-Écosse et le Nouveau-Brunswick sont les provinces qui subiraient les plus fortes réductions d'émissions de polluants atmosphériques, en grande partie attribuables à l'abandon des centrales au gaz naturel au profit de sources de production d'électricité peu ou non émettrices. Dépendamment de la localisation de ces réductions d'émissions de polluants atmosphériques, il est attendu que le projet de règlement améliorerait la qualité de l'air au niveau local. Il convient de noter que la biomasse, la biomasse avec les systèmes de CSC et le gaz naturel avec CSC sont associés à des émissions de polluants atmosphériques provenant de la production d'électricité. Par conséquent, les provinces où ces technologies sont mises en place de façon progressive et importante pourraient connaître des réductions différentielles globales de polluants atmosphériques moins importantes que les provinces qui misent davantage sur des types de technologies sans émission.

La pollution de l'air est reconnue mondialement comme un facteur majeur de développement de maladies et de décès prématurés et constitue un facteur de risque environnemental clé pour la santé humaine au Canada. L'exposition à la pollution atmosphérique augmente le risque de mortalité prématurée par cardiopathie, accident vasculaire cérébral et cancer du poumon, ainsi que le risque de maladies respiratoires et cardiovasculaires. Les enfants, les personnes âgées et les personnes souffrant de problèmes de santé sous-jacents sont particulièrement vulnérables aux effets néfastes de la pollution atmosphérique. Par ailleurs, les preuves scientifiques montrent que les effets néfastes sur la santé se produisent à des concentrations très faibles pour de nombreux polluants, sans indication d'un seuil en dessous duquel il n'y a pas de risques. Par conséquent, une légère diminution de la pollution atmosphérique est associée à une réduction du risque d'effets néfastes sur la santé pour les populations exposées. En 2015, le ministère de la Santé a estimé que la pollution atmosphérique provenant des groupes de production d'électricité contribue à environ 150 décès prématurés par an au Canada, ainsi qu'à de nombreuses conséquences non fatales, pour un coût total de 1,2 milliard de dollars par an (dollars constants de 2015).[30] Alors que les effets négatifs sur la santé devraient être considérablement atténués par le *Règlement modifiant le Règlement sur la réduction des émissions de dioxyde de carbone — secteur de l'électricité thermique au charbon*, le projet de règlement devrait également réduire les effets négatifs sur la santé.

Le projet de règlement permettrait également de réduire les émissions de mercure de 1 029 kilogrammes, dont la majeure partie se situerait dans le sud de la Saskatchewan. L'exposition au mercure est associée à un large éventail d'effets néfastes sur la santé humaine (notamment, le système nerveux est sensible à

[30] Impacts sur la santé de la pollution de l'air au Canada provenant du transport, de l'industrie et de la combustion résidentielle.

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la toxicité du mercure), les fœtus et les enfants en développement étant les plus sensibles à ces effets néfastes sur la santé.

Les répercussions sur la qualité de l'air et les bénéfices sanitaires associés n'ont pas été quantifiés ni monétisés dans cette analyse. Cependant, les réductions des émissions de polluants atmosphériques associées au projet de règlement devraient réduire le risque d'effets néfastes sur la santé des populations concernées, ce qui se répercuterait comme un bénéfice économique dans l'avenir.

Avantages potentiels pour l'environnement

Dans la mesure où les réductions de la pollution atmosphérique décrites dans le tableau 12 améliorent la qualité de l'air au niveau local, le projet de règlement peut également réduire les nuisances environnementales en améliorant la visibilité, en évitant les coûts de nettoyage des surfaces, en améliorant le rendement des cultures, en améliorant la santé des écosystèmes forestiers et en réduisant le risque de maladie ou de décès prématuré chez les populations sensibles d'animaux sauvages ou d'élevage, en fonction de ce qui se trouve à proximité du site d'émission. Comme pour les avantages potentiels pour la santé, les répercussions sur la qualité de l'air et les bénéfices environnementaux associés n'ont pas été quantifiés ni monétisés dans cette analyse.

Économies de carburant

Les centrales émettrices ont besoin d'une source de combustible pour produire de l'électricité (gaz naturel, mazout lourd, mazout léger, gaz de pétrole liquéfié, biomasse, déchets, etc.) En revanche, les groupes non émetteurs utilisent des sources d'énergie renouvelables telles que l'eau, le vent, la chaleur ou le soleil pour produire de l'électricité, qui sont toutes fournies par l'environnement naturel. À l'exception des centrales qui mettent en œuvre le CSC,[31] le passage des types de centrales émettrices à des types de centrales à peu ou non émettrices en vertu du projet de règlement réduirait considérablement les coûts opérationnels du secteur de la production d'électricité en ce qui concerne les carburants. En utilisant les résultats du modèle E3MC, l'ACA estime que le projet de règlement entraînerait des économies totales de 13,5 milliards de dollars en carburant pour les groupes de production d'électricité au cours de la période d'analyse de 27 ans. La répartition de ces économies par province est présentée au tableau 13.

Tableau 13. Économies différentielles de carburant par province (millions de dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)
T.-N.-L.	0	54	237	103	48	442	21
Î.-P.-É.	0	4	8	1	0	13	1
N.-É.	-5	147	651	661	532	1 986	96

[31] Les types d'installations dotées de systèmes de CSC sont capables de réduire la grande majorité de leurs émissions de GES en capturant et en stockant ces émissions (généralement sous terre) au lieu de les rejeter dans l'atmosphère. Cependant, ces technologies de CSC s'accompagnent de compromis au niveau de l'utilisation des combustibles et de la pollution atmosphérique associée. Plus précisément, les centrales dotées du CSC utilisent davantage de combustible pour produire un mégawatt heure d'électricité que leurs homologues sans CSC, afin d'alimenter les systèmes qui stockent les émissions de gaz à effet de serre. Étant donné que plus de carburant est brûlé, une augmentation proportionnelle des polluants atmosphériques est rejetée dans l'atmosphère (parce que les technologies de CSC ne capturent et ne stockent que les GES, et non les polluants atmosphériques). Ce phénomène est parfois appelé « pénalité énergétique ».

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N.-B.	4	81	279	64	130	558	27
Qué.	0	6	28	26	24	84	4
Ont.	-23	245	1 484	1 798	1 353	4 858	235
Man.	0	0	0	0	0	0	0
Sask.	-2	100	632	718	701	2 148	104
Alb.	2	135	899	1 035	1 141	3 211	155
C.-B.	0	13	74	69	66	222	11
Yn.	0	0	0	0	0	0	0
T.N.-O.	0	0	0	0	0	0	0
Nt.	0	0	0	0	0	0	0
Total	-25	785	4 292	4 475	3 994	13 522	653

* Les dépenses en combustibles augmentent au cours des premières années de la période d'analyse en raison de l'évolution de la production par rapport aux importations, ainsi que de l'utilisation de combustibles provenant des nouvelles technologies du réseau électrique dont la construction est modélisée au cours de cette période (c'est-à-dire la production d'électricité au gaz naturel avec système de CSC, et la production d'électricité avec de la biomasse). Cette observation vaut également pour les coûts variables d'exploitation et d'entretien.

Un exemple détaillé de la manière dont les économies de carburant ont été calculées sera fourni sur demande par le département dans les mois à venir.

Économies sur les coûts variables d'opération et de maintenance

Si l'on considère tous les types de centrales peu ou non émettrices, le coût moyen d'opération et de maintenance de ces groupes sur une base variable (par MWh de production) est inférieur à celui des types de centrales émettrices. Ainsi, le passage de types de centrales émettrices à des types de centrales peu ou non émettrices dans le cadre du projet de règlement tendrait à réduire les coûts variables d'opération et de maintenance (VOM) pour le secteur de l'électricité. En utilisant les résultats du modèle E3MC, l'ACA estime que le projet de règlement entraînerait des économies totales de 1,4 milliard de dollars en coûts VOM au cours de la période d'analyse de 27 ans. La répartition de ces économies par province est présentée au tableau 14.

Tableau 14. Économies différentielles sur les coûts variables d'opération et de maintenance par province (millions de dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)
T.-N.-L.	0	2	9	3	2	16	1
Î.-P.-É.	0	0	1	1	1	3	0
N.-É.	0	8	26	30	29	93	4
N.-B.	1	10	26	10	19	67	3
Qué.	0	0	-1	-1	0	-2	0
Ont.	-3	32	147	166	140	482	23
Man.	0	0	0	0	0	0	0
Sask.	0	17	85	63	40	205	10
Alb.	-5	23	264	185	182	650	31
C.-B.	-1	-8	-25	-32	-45	-111	-5
Yn.	0	0	0	0	0	0	0
T.N.-O.	0	0	0	0	0	0	0
Nt.	0	0	0	0	0	0	0

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Total	-7	83	531	426	368	1 402	68

Un exemple détaillé de la manière dont les économies de coûts variables d'opération et de maintenance ont été calculées sera fourni sur demande par le département dans les mois à venir.

Réduction des coûts de mise à neuf

Les coûts de mise à neuf sont des coûts d'investissement périodiques entrepris à la fin de la durée de vie opérationnelle d'un groupe, dépensés pour remettre un groupe dans un état similaire à celui de sa mise en service initiale. Le modèle E3MC n'applique pas le concept de durée de vie opérationnelle d'un groupe et, par conséquent, le modèle assume que de nombreux groupes continuent à fonctionner, quel que soit leur âge. Pour s'assurer que les coûts de mise à neuf périodique sont pris en compte dans l'analyse, l'ACA applique un coût supplémentaire aux groupes l'année où ils atteignent la fin de leur durée de vie utile. Une fois ce surcoût appliqué, l'ACA modélise ce groupe pour une autre durée de vie utile, après laquelle le surcoût serait à nouveau encouru. Ce cycle se répète de la date de mise en service d'un groupe jusqu'à la fin de la période d'analyse en 2050.

L'ACA conçoit le coût de mise à neuf comme étant celui associé au remplacement d'un ancien groupe sur le même site. Ce coût type de remplacement utilise l'infrastructure d'un ancien groupe comme base, ce qui est beaucoup moins coûteux que la construction d'un nouveau groupe dans une nouvelle zone. La différence de coût la plus importante entre la construction d'un nouveau groupe sur un site existant et celle d'un nouveau groupe sur un nouveau site est la présence de lignes d'alimentation en combustible et de lignes de transmission d'électricité qui relient les groupes en amont et en aval. L'ACA part de l'hypothèse prudente que le coût de la construction d'une nouvelle centrale sur un site existant est d'un tiers de celui de la construction d'une nouvelle centrale sur un nouveau site, quel que soit le type de centrale. Cette hypothèse prudente sous-estime probablement l'ampleur des économies qui seraient réalisées.

En vertu du projet de règlement, les provinces ayant une grande quantité de capacité émettrice dans le scénario de référence devraient voir les coûts de mise à neuf réduits dans le scénario réglementaire à mesure que les groupes sont retirés, à deux exceptions près. La première exception concerne les groupes au gaz naturel sans dispositif de réduction des émissions qui se convertissent au gaz naturel avec CSC, qu'on suppose respecter leur calendrier de remise en état initial, mais dont les coûts de mise à neuf seraient désormais plus élevés à la fin de leur durée de vie utile. La deuxième exception concerne le stockage de l'électricité, dont la durée de vie est plus courte que celle des autres infrastructures du réseau électrique. Dans l'ensemble, la modélisation de l'ACA estime que le projet de règlement permettrait de réaliser des économies supplémentaires de 55 millions de dollars sur les coûts de remise à neuf au cours de la période d'analyse de 27 ans. La distribution des économies de coûts de remise à neuf par province est présentée au tableau 15.

Tableau 15. Économies différentielles liées à la remise à neuf par province (millions de dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)
T.-N.-L.	0	0	11	29	0	41	2
Î.-P.-É.	0	0	0	0	0	0	0
N.-É.	0	0	-24	0	0	-24	-1
N.-B.	0	0	0	0	0	0	0

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Qué.	0	30	-6	3	0	27	1
Ont.	0	48	101	0	0	149	7
Man.	0	0	0	0	0	0	0
Sask.	0	0	-5	-85	0	-90	-4
Alb.	99	0	0	-219	-78	-198	-10
C.-B.	0	0	111	-9	49	151	7
Yn.	0	0	0	0	0	0	0
T.N.-O.	0	0	0	0	0	0	0
Nt.	0	0	0	0	0	0	0
Total	99	77	189	-281	-28	55	3

Coûts

À mesure que les sources de production d'électricité émettrices sont remplacées par des sources peu ou non émettrices, le projet de règlement entraînerait des coûts supplémentaires liés à la construction de nouvelles capacités de production et de stockage, à la construction de nouvelles lignes de transmission, aux opérations fixes et à la maintenance, à la valeur résiduelle du capital en cas de mise hors service anticipée et à l'augmentation des dépenses nettes d'importation ainsi que l'augmentation des coûts administratifs et gouvernementaux.

Chacun de ces coûts est décrit en détail dans les sous-sections ci-dessous.

Coûts d'investissement pour les nouvelles capacités du réseau électrique

La nouvelle capacité du réseau électrique désigne l'augmentation d'une année à l'autre de la capacité de production et de stockage requise à la fois dans le scénario de référence et dans le scénario réglementaire pour répondre à la demande d'énergie et à d'autres contraintes. Le projet de règlement entraînerait une diminution des nouveaux investissements dans les types de centrales émettrices et une augmentation des nouveaux investissements dans les types de centrales peu ou non émettrices. La plupart des types de centrales non émettrices ont un coût d'investissement par MW de capacité plus élevée que leurs homologues émettrices. Les types de centrales émettrices dotées d'un système de captage et de stockage du carbone ont également un coût d'investissement par MW de capacité plus élevée que leurs homologues sans dispositif de réduction d'émissions. Par conséquent, les économies associées à l'abandon de nouvelles capacités émettrices sont généralement inférieures aux coûts associés à la mise en chantier de nouvelles capacités peu ou non émettrices.

En utilisant les résultats du modèle E3MC, l'ACA estime que le projet de règlement entraînerait un total de 53,7 milliards de dollars en coûts d'investissement différentiels dans le secteur de la production d'électricité pour la nouvelle capacité du réseau électrique au cours de la période d'analyse de 27 ans. Ces coûts d'infrastructure sont répartis par province, comme le montre le tableau 16, et par type de technologie, comme le montre le tableau 17. Le coût en capital total réparti par province est présenté au tableau 16, et le coût en capital moyen annualisé par type de technologie et province est présenté au tableau 17.

Tableau 16. Coût d'investissement différentiel pour la nouvelle capacité du réseau électrique par province (millions de dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)
T.-N.-L.	0	0	780	210	1 235	2 225	107
Î.-P.-É.	0	0	0	0	0	0	0

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N.-É.	1 648	3 730	642	743	-623	6 140	297
N.-B.	0	0	1 405	4 340	0	5 745	277
Qué.	2	294	64	0	-79	281	14
Ont.	-63	3 900	10 251	-1 225	217	13 081	632
Man.	0	0	0	0	0	0	0
Sask.	340	1 241	2 467	30	2 628	6 707	324
Alb.	2 607	14 606	683	357	-1 340	16 914	817
C.-B.	0	1 626	953	88	-93	2 574	124
Yn.	0	0	0	0	0	0	0
T.N.-O.	0	0	0	0	0	0	0
Nt.	0	0	0	0	0	0	0
Total	4 534	25 398	17 246	4 543	1 946	53 667	2 592

Tableau 17. Coût en capital moyen annualisé (n=27) pour les nouvelles capacités de production d'électricité par type de technologie et province (millions de dollars)

	T.-N.-L.	N.-É.	N.-B.	Qué.	Ont.	Sask.	Alb.	C.-B.	Total
TCPG	0	43	-13	0	-2	-19	-43	0	-34
CCPG	0	0	-25	0	-4	-36	-82	0	-147
Petit CCPG	0	-14	-28	0	-4	-40	-90	0	-177
GN CSC	0	0	0	0	0	181	820	0	1,001
Nucléaire	0	0	281	0	0	204	196	0	681
Hydro, charge de base	26	27	38	0	0	4	55	1	151
Hydro, de pointe	0	0	0	14	452	0	0	94	560
Petites centrales hydroélectriques	21	0	0	-3	95	7	-84	10	45
Biomasse	12	138	25	0	10	3	48	2	238
Biomasse CSC	0	40	0	0	105	9	12	11	138
Éolien terrestre	18	73	-0,1	2	-25	4	-24	5	52
Énergie éolienne en mer	27	19	-0,04	0	0	0	0	0	46
PV solaire	-0,1	2	0	-0,01	4	8	5	0,1	19
Stockage	4	8	0	1	2	-1	4	2	19
Total	107	297	277	14	632	324	817	124	2,592

* Les dépenses en immobilisations liées au captage et stockage du carbone à partir du gaz naturel comportent deux volets : la construction de nouveaux systèmes de captage et de stockage et la mise à niveau des groupes existants alimentés au gaz naturel pour déployer les systèmes de captage et stockage du carbone.

Comme le montre le tableau 16, l'Île-du-Prince-Édouard, le Manitoba, le Yukon, les Territoires du Nord-Ouest et le Nunavut ne devraient pas entreprendre d'importants développements de technologies sur le réseau électrique en réponse au projet de règlement, tandis que de nouveaux investissements importants sont attendus en Alberta, en Ontario, en Saskatchewan, Nouvelle-Écosse et Nouveau-Brunswick. Comme le montre le tableau 17, la majorité des coûts en capital pour ces provinces seraient attribuables à la construction de centrales utilisant la biomasse en Nouvelle-Écosse, de centrales nucléaires au Nouveau-Brunswick, de l'hydroélectricité de pointe en Ontario, de centrales nucléaires en Saskatchewan

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et du CSC associé à la production d'électricité au gaz naturel en Alberta. Dans l'ensemble, le projet de règlement entraînerait une diminution de la construction de nouveaux capitaux pour les technologies de production d'électricité sans dispositif de réduction des émissions (TCPG, CCPG et petit CCPG), jumelé à une augmentation de la construction de tous les autres types de technologies de réseaux électriques.

Un exemple détaillé de la manière dont les coûts d'investissement pour les nouvelles capacités de production d'électricité ont été calculés sera fourni sur demande par le département dans les mois à venir. Le coût pour le Gouvernement de l'adoption progressive de l'ITC modélisé associé aux coûts d'investissement pour le secteur de la production d'électricité indiqués dans le tableau 16 est présenté dans la sous-section consacrée aux coûts pour le Gouvernement.

Coût du capital pour les nouvelles lignes de transmission

La modélisation faite avec le modèle NextGrid indique que minimiser les coûts du projet de règlement à l'échelle nationale, tout en assurant sa fiabilité, impliquerait que les provinces construisent certaines interconnexions pour faciliter le mouvement de l'électricité produite au pays. En utilisant les résultats du modèle NextGrid, l'ACA estime que le projet de règlement entraînerait un total de 6,7 milliards de dollars de coûts d'immobilisation supplémentaires pour de nouvelles lignes de transmission interprovinciales au cours de la période d'analyse de 27 ans. L'ACA suppose que le coût en capital de toutes les nouvelles lignes de transmission serait partagé également entre les deux provinces que la ligne relie. La répartition de ces coûts d'infrastructure par province est présentée au tableau 18.

Tableau 18. Coût d'immobilisation différentiel pour les nouvelles lignes de transport par province (millions de dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)
T.-N.-L.	0	0	0	0	0	0	0
Î.-P.-É.	0	79	0	0	0	79	4
N.-É.	0	0	0	0	0	0	0
N.-B.	0	79	0	0	0	79	4
Qué.	0	0	558	0	0	558	27
Ont.	0	443	597	52	291	1 383	67
Man.	0	443	38	70	486	1 038	50
Sask.	0	437	0	18	196	651	31
Alb.	0	1 132	0	374	146	1 653	80
C.-B.	0	694	0	374	146	1 215	59
Yn.	0	0	0	0	0	0	0
T.N.-O.	0	0	0	0	0	0	0
Nt.	0	0	0	0	0	0	0
Total	0	3 309	1 193	889	1 265	6 656	321

Étant donné que le développement et la mise en œuvre d'une nouvelle ligne de transport interprovinciale nécessitent de nombreuses années avant que celle-ci soit opérationnelle, toutes les interconnexions qui seraient mises en service entre 2024 et 2030 sont déjà planifiées et, par conséquent, ne sont pas considérées comme des coûts supplémentaires par rapport au projet de règlement. Les coûts du tableau 18 ont été calculés en multipliant la capacité de transport modélisée (MW) par le coût marginal en capital du transport estimé ($/MW), comme indiqué dans le tableau 19. La variation du coût marginal du capital de transport est attribuable aux différentes distances des lignes (kilomètres) ainsi qu'aux différences provinciales en matière de géographie et de permis.

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Tableau 19. Capacité de transmission différentielle et coût marginal estimé du capital de transmission

Provinces connectées	Capacité de transmission modélisée (MW)	Coût marginal moyen du capital de transmission ($/MW, millions de dollars, dollars constants de 2022, non actualisés)
N.-B. — Î.-P.-É.	125	1,6
Ont. —Qué.	2 000	0,8
Man. — Ont.	666	3,6
Man. — Sask.	110	3,3
Sask. — Man.	108	3,3
Alb. — Sask.	300	3,7
C.-B. — Alb.	2 100	1,6

Le projet de règlement ne devrait pas inciter à étendre les interconnexions aux territoires, car la plupart des groupes de production dans les territoires ont une capacité inférieure à 25 MW et ne sont pas branchés à un réseau électrique réglementé par la NERC, ce qui les exclut du champ d'application du projet de règlement. Il convient de noter que l'analyse coûts-avantages ne tient pas compte des nouvelles lignes de transport intraprovinciales qui pourraient être nécessaires pour relier les nouvelles infrastructures au réseau électrique, étant donné que l'on suppose que les nouvelles infrastructures utiliseront les lignes de transport intraprovinciales existantes.

Coûts fixes d'opération et de maintenance

Si l'on considère tous les types de centrales à peu ou non émettrices, le coût moyen d'opération et de maintenance sur une base fixe (par MW de capacité) est plus élevé que celui des types de centrales sans dispositif de réduction des émissions. Ainsi, le passage de types de centrales émettrices à des types de centrales peu ou non émettrices dans le cadre du projet de règlement aurait tendance à augmenter les coûts fixes d'opération et de maintenance pour le secteur de l'électricité. E3MC suggère que le projet de règlement entraînerait un total de 6,4 milliards de dollars en coûts fixes d'opération et de maintenance au cours de la période d'analyse de 27 ans. La répartition de ces coûts par province est présentée dans le tableau 20.

Tableau 20. Coûts fixes différentiels de O&M par province (millions de dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)
T.-N.-L.	0	-4	28	68	165	257	12
Î.-P.-É.	0	0	-2	-2	-2	-6	0
N.-É.	30	60	146	219	178	633	31
N.-B.	0	0	26	511	463	1 001	48
Qué.	0	3	19	12	6	40	2
Ont.	-3	-38	200	159	31	350	17
Man.	0	0	0	0	0	0	0
Sask.	5	62	182	253	301	802	39
Alb.	57	490	1 045	966	799	3 357	162
C.-B.	0	-16	-24	-7	-10	-57	-3
Yn.	0	0	0	0	0	0	0
T.N.-O.	0	0	-2	-2	-2	-6	0
Nt.	0	0	0	0	0	0	0

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Total	89	556	1 619	2 179	1 930	6 372	308

Un exemple détaillé de la manière dont les coûts fixes d'opération et de maintenance ont été calculés sera fourni sur demande par le département dans les mois à venir.

Valeur résiduelle du capital en cas de mise hors service anticipée

Comme indiqué précédemment, le projet de règlement ne prescrit aucune voie de conformité particulière pour un groupe particulier qui ne respecterait pas la limite d'intensité des émissions de CO_2 à partir de 2035, et tous les résultats présentés dans l'analyse coûts-avantages représentent un scénario modélisé indiquant ce qui pourrait se produire en réponse au projet de règlement dans le cadre d'un scénario central. Dans ce cas central, le modèle NextGrid a modélisé les décisions qui pourraient être prises concernant les groupes existants qui ne respectent pas la limite d'intensité des émissions de CO_2 à partir de 2035 (c.-à-d., mise hors service anticipée, mise à niveau avec système de CSC ou changement du régime d'exploitation pour opérer selon la flexibilité basée sur les heures d'opérations et la masse d'émissions), tandis que le modèle E3MC a modélisé les décisions qui pourraient être prises par tous les autres groupes.

Selon la modélisation du cas central, la majorité des groupes émetteurs sans dispositif de réduction des émissions (56 %) continueraient à fonctionner de manière limitée dans le cadre de la flexibilité basée sur les heures d'opérations et la masse d'émissions à partir de l'année où la limite d'intensité des émissions de CO_2 commence à s'appliquer à ces groupes, afin de fournir une capacité d'appoint au réseau électrique à des fins de fiabilité. Une autre proportion de groupes émetteurs sans dispositif de réduction des émissions (35 %) continuerait à fonctionner en mettant en œuvre un système de captage et de stockage du carbone pour respecter la limite d'intensité des émissions de CO_2. Une minorité de groupes émetteurs concernés (9 %) se retireraient plus tôt qu'ils ne l'auraient fait en l'absence du projet de règlement.

En utilisant les résultats du modèle E3MC pour monétiser les mises hors service anticipées établies par le modèle NextGrid comme voie de conformité, l'ACA estime que la valeur résiduelle du capital de celles-ci totaliserait 1,3 milliard de dollars au cours de la période analytique de 27 ans (ou une moyenne annualisée de 65 millions de dollars sur 27 ans), dont la totalité devrait se produire en 2035. Ces coûts ont été estimés en multipliant d'abord la capacité (kW) de chaque groupe mis hors service en 2034 (c.-à-d. leur dernière année de pleine production) par le coût marginal du capital de la capacité de production ($/kW) de ces groupes en 2035. Cela représente le coût de la construction d'un nouveau groupe d'une capacité équivalente au cours de l'année de mise hors service. Pour transformer cette valeur totale en valeur résiduelle du capital mis hors service, ces nouveaux coûts ont ensuite été multipliés par la fraction de la durée de vie restante de chaque groupe, sur la base de leur date de mise en ligne, qui est une approximation de leur date de mise en service.

Dans la mesure où d'autres capitaux devraient être constitués (ou les importations devraient augmenter) pour remplacer la production fournie par les groupes qui feraient l'objet d'une mise hors service anticipée, l'attribution d'un coût à la mise hors service anticipée peut constituer un double comptage du point de vue de l'ACA. Cependant, ce coût est conservé dans l'ACA pour tenir compte des coûts des industries qui peuvent découler du service de la dette impayée sur les actifs qui cessent de fonctionner.

Augmentation des dépenses d'importations nettes internationales

À l'aide des résultats du modèle E3MC, l'ACA estime que les recettes d'exportation internationales supplémentaires diminueraient de 5,6 milliards de dollars (diminution de 2 % par rapport au scénario de référence), tandis que les dépenses d'importation supplémentaires augmenteraient de 6 millions de dollars (augmentation de 0,01 % par rapport au scénario de référence). En conséquence, les dépenses nettes d'importation (dépenses d'importation moins recettes d'exportation) provenant du commerce

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international augmenteraient de 5,6 milliards de dollars sur la période d'analyse de 27 ans. La répartition des dépenses d'importation nettes différentielles par province est présentée dans le tableau 21.

Tableau 21. Dépenses différentielles d'importations nettes internationales par province (millions de dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)
T.-N.-L.	0	0	0	-0	-0	0	0
Î.-P.-É.	0	0	0	-0	-0	0	0
N.-É.	0	0	0	- 0	- 0	0	0
N.-B.	-12	-41	-85	-118	-54	-309	-15
Qué.	69	449	-1 274	998	1 758	2 000	97
Ont.	-41	534	-972	-686	-202	-1 365	-66
Man.	12	390	1 296	1 488	752	3 938	190
Sask.	-0	5	5	-58	-54	-103	-5
Alb.	-0	3	21	26	20	70	3
C.-B.	13	17	-110	303	1 127	1 350	65
Yn.	- 0	- 0	- 0	- 0	- 0	0	0
T.N.-O.	- 0	0	0	- 0	- 0	0	0
Nt.	0	0	0	- 0	- 0	0	0
Total	41	1 357	-1 118	1 953	3 348	5 581	270

Un exemple détaillé de la manière dont les recettes nettes d'exportation de combustible ont été calculées sera fourni sur demande par le département dans les mois à venir. L'ACA suppose qu'il n'y aurait pas de différence significative dans l'intensité moyenne des émissions de l'électricité produite au Canada par rapport à celle produite aux États-Unis aux fins du commerce bilatéral. Les fuites de carbone ne devraient pas constituer un risque pour la réalisation des dommages évités liés au changement climatique présentés dans la sous-section sur les avantages.

L'ACA considère que les répercussions que le projet de règlement pourrait avoir sur les dépenses d'importations nettes nationales sont transférées et sont donc analysées dans la section de l'analyse distributive. Il convient de noter que, sous réserve de certaines contraintes, le commerce est une alternative à la constitution de capital et serait choisi lorsque cette dernière est relativement plus coûteuse. Ainsi, les provinces qui devraient augmenter leurs importations nettes internationales ou intérieures éviteraient également une augmentation des coûts en capital pour la nouvelle capacité de production d'électricité. En d'autres termes, si les répercussions estimées sur le commerce ne se produisaient pas comme prévu par le modèle, le coût en capital supplémentaire pour la nouvelle capacité du réseau électrique décrit dans le tableau 16 augmenterait proportionnellement pour les provinces dépendantes des importations.

Frais administratifs

Comme indiqué dans la section Description, les exigences administratives prévues par le projet de règlement s'appliqueraient à tout groupe de production d'électricité à partir de combustibles fossiles d'une capacité supérieure ou égale à 25 MW qui est connectée à un réseau électrique réglementé par la NERC, tandis que les exigences de conformité (c'est-à-dire le respect de la norme de rendement de 30 t/GWh ou une exception appropriée) s'appliqueraient à tout groupe qui produit de l'électricité à partir de combustibles fossiles, d'une capacité supérieure ou égale à 25 MW, et qui a un solde exportateur vers un réseau électrique réglementé par la NERC supérieur à zéro gigawattheure. Conformément à la modélisation effectuée avec le modèle NextGrid, l'ACA estime que 125 installations seraient soumises à

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des exigences administratives,[32] dont 124 devraient soumettre des rapports annuels complets. Bien que certaines installations puissent être composées de plusieurs groupes de production d'électricité, l'ACA suppose que les mêmes coûts administratifs « par événement » seraient encourus pour chaque installation, quel que soit le nombre de groupes contenus dans chacune d'entre elles. Les hypothèses utilisées pour évaluer les coûts administratifs sont présentées dans le tableau 22.

Tableau 22. Hypothèses de coûts administratifs, par activité administrative (dollars constants de 2022, non actualisés)

Activité administrative	Calendrier	Nombre d'installations (en 2024)	Catégorie professionnelle	Heures consacrées	Taux de salaire horaire (y compris les frais généraux)	Coût approximatif par événement
Familiarisation avec les exigences administratives	2024	125	Professions des sciences naturelles et appliquées	12,0	53,38 $	641 $
Familiarisation avec les exigences administratives	2024	125	Professions juridiques et services sociaux, communautaires et gouvernementaux	8,0	53,43 $	427 $
Familiarisation avec les exigences administratives	2024	125	Professions d'encadrement supérieur	4,0	76,77 $	307 $
Rapport d'enregistrement — informations sur le groupe et diagramme de flux	2024	125	Sciences naturelles et appliquées et professions connexes	4,0	53,38 $	214 $
Attribution du numéro d'enregistrement	2024	125	Personnel de bureau	0,5	31,19 $	16 $
Rapport annuel — recherche et saisie des données, échantillonnage et analyse, calculs (émissions de CO_2, production d'électricité, solde exportateur), envoi du rapport.	À partir de 2035	124	Sciences naturelles et appliquées et professions connexes	20,0	53,38 $	1 068 $
Rapport annuel succinct — calculer le solde exportateur, envoyer le rapport	À partir de 2035	1	Sciences naturelles et appliquées et professions connexes	3,0	53,38 $	160 $
Rapport annuel — calcul de l'énergie thermique nette produite	À partir de 2035	75	Sciences naturelles et appliquées et professions connexes	4,0	53,38 $	214 $

[32] La répartition des 125 installations concernées est estimée comme suit : 75 installations du SCIAN 2211 (Production, transport et distribution d'électricité), 16 installations du SCIAN 2111 (Extraction de pétrole et de gaz), 28 installations du SCIAN 3221 (Usines de pâte à papier, de papier et de carton), deux installations du SCIAN 3311 (Sidérurgie), une installation du SCIAN 3251 (Fabrication de produits chimiques de base), une installation du SCIAN 3241 (Fabrication de produits du pétrole et du charbon), une installation du SCIAN 4881 (Activités de soutien au transport aérien), et une installation du SCIAN 6113 (Universités).

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Rapport annuel — Émissions captées par le système CSC	À partir de 2035	19	Sciences naturelles et appliquées et professions connexes	4,0	53,38 $	214 $
Rapport annuel — Émissions de CO_2 associées à l'hydrogène ou à la vapeur achetée	À partir de 2035	19	Sciences naturelles et appliquées et professions connexes	1,0	53,38 $	53 $
Rapport annuel — approbation	À partir de 2035	124	Professions gestionnaires supérieures	2,0	76,77 $	154 $
Rapport annuel succinct — approbation	À partir de 2035	1	Professions gestionnaires supérieures	0,5	76,77 $	38 $
Rapport annuel — enregistrement des données associées	À partir de 2035	125	Personnel de bureau	1,0	31,19 $	31 $

Dans le cadre du scénario réglementaire, la modélisation effectuée avec le modèle NextGrid estime que la capacité totale de tous les groupes de production d'électricité à partir de combustibles fossiles diminuerait de 8,53 % au total entre 2024 et 2050, soit une diminution moyenne de 0,34 % par an. Cette diminution annuelle moyenne de la capacité a été utilisée comme approximation de la croissance négative du nombre d'installations touchées au cours de la période d'analyse. En utilisant les données du tableau 22 et le taux de croissance négatif des installations concernées, le projet de règlement devrait entraîner des coûts administratifs supplémentaires de 2,0 millions de dollars pour l'industrie au cours de la période d'analyse de 27 ans.

Coûts pour le Gouvernement

Le projet de règlement devrait entraîner un total de 104 millions de dollars en coûts gouvernementaux supplémentaires au cours de la période d'analyse de 27 ans. De ce total, la modélisation du cas central estime que le gouvernement dépenserait 55 millions de dollars en financement fédéral supplémentaire dans le cadre du CII modélisé associé à l'expansion progressive des technologies admissibles indiquées dans le tableau 16. Le gouvernement dépenserait également 48 millions de dollars pour l'administration du programme, principalement sous forme de nouveaux salaires pour le ministère, qui commenceraient à être versés en 2024, lorsque l'on propose d'enregistrer le règlement. Les coûts associés à la promotion de la conformité (c.-à-d. les coûts liés à l'élaboration, à l'affichage et à la distribution de matériel promotionnel) devraient être minimes, car le bassin de parties touchées est limité et connu.

En outre, le ministère devrait engager 1 million de dollars de coûts supplémentaires liés à la formation, aux inspections, aux enquêtes et aux mesures prises en cas d'infractions présumées, ainsi qu'aux activités de mise en conformité et de promotion. Un coût unique de 58 192 $ serait également nécessaire pour la formation des agents de contrôle, ainsi qu'un coût unique de 84 195 $ pour le travail d'évaluation des renseignements stratégiques (en dollars de 2022, non actualisés). L'ACA suppose que ces coûts surviendraient en 2034, un an avant l'année où les limites d'intensité des émissions commenceront à s'appliquer aux groupes touchés. Des coûts récurrents (annuels) de 32 912 $ seraient nécessaires pour l'administration, la coordination et l'analyse afin de soutenir les activités d'application, ainsi que 94 743 $ pour l'application, répartis comme suit : 15 259 $ pour les inspections (qui comprennent les coûts d'opération et de maintenance, les coûts de transport et d'échantillonnage) et les mesures prises en cas d'infractions présumées (y compris les avertissements, les ordres de conformité en matière de protection de l'environnement et les injonctions), 1 073 $ pour les enquêtes, 2 378 $ pour les poursuites et 43 121 $ pour l'acquisition continue de renseignement (en dollars de 2022, non actualisés). L'ACA suppose que ces coûts commenceraient en 2035, année où les limites d'intensité des émissions commenceront à s'appliquer aux groupes touchés.

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Déclaration coûts-avantages

Nombre d'années : 27 ans (2024 à 2050)
Année de référence pour le calcul des coûts : 2022
Valeur actuelle de l'année de référence : 2023
Taux d'actualisation : 2 %

Tableau 23. Résumé des avantages différentiels totaux (en millions de dollars, sauf indication contraire)

Description	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)
Principal avantage : atténuation du changement climatique	-310	3 514	20 030	22 568	23 665	69 468	3 355
Co-bénéfice : atténuation du changement climatique	635	1 489	5 436	5 346	5 163	18 069	873
Réduction des coûts pour l'industrie	67	946	5 013	4 619	4 334	14 979	723
Total des avantages monétaires	392	5 949	30 479	32 534	33 162	102 516	4 951
Principal avantage : réduction de la pollution atmosphérique (en kilotonnes)	11	34	183	122	118	467	17
Co-bénéfice : réduction de la pollution atmosphérique (en kilotonnes)	4	6	26	52	52	140	5
Avantages quantifiés totaux (en kilotonnes)	15	40	209	174	169	607	22

Tableau 24. Résumé des coûts différentiels totaux (en millions de dollars)

Description	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)
Coûts d'investissement pour les nouvelles capacités du réseau électrique	4 534	25 398	17 246	4 543	1 946	53 667	2 592
Coûts d'investissement pour les nouvelles lignes de transmission	0	3 309	1 193	889	1 265	6 656	321
Coûts fixes d'opération et de maintenance	89	556	1 619	2 179	1 930	6 372	308
Valeur résiduelle du capital en cas de mise hors service anticipée	0	1 263	0	0	0	1 263	61

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Coût net des importations internationales	41	1 357	-1 118	1 953	3 348	5 581	270
Frais administratifs	0,2	0,1	0,6	0,6	0,5	2	0,1
Coûts pour le Gouvernement	66	26	5	4	4	104	8
Coûts totaux	4 731	31 910	18 945	9 568	8 492	73 647	3 557

Tableau 25. Déclaration des coûts et avantages du projet de règlement (millions de dollars)

Description	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)
Total des avantages monétaires*	392	5 949	30 479	32 534	33 162	102 516	4 951
Total des coûts monétisés	4 731	31 910	18 945	9 568	8 492	73 647	3 557
Bénéfices nets totaux	-4 339	-25 961	11 533	22 966	24 670	28 869	1 394

* Les avantages totaux sont probablement sous-estimés, car les avantages potentiels pour la santé et l'environnement qui résulteraient au fil du temps de la réduction des émissions de polluants atmosphériques n'ont pas été monétisés dans l'analyse coûts-avantages.

Comme le montre le tableau 25, on estime que le projet de règlement se traduira par un total de 28,9 milliards de dollars d'avantages nets monétisés pour la société au cours de la période d'analyse de 27 ans, soit 1,4 milliard de dollars d'avantages nets par an sur une base annualisée.

Analyse de la répartition

Coûts et économies par province

On s'attend à ce que le projet de règlement entraîne une augmentation importante des échanges interprovinciaux d'électricité, grandement facilitée par les nouvelles interconnexions provinciales modélisées à l'aide du modèle NextGrid afin de minimiser les coûts de conformité à l'échelle du réseau. Avec les interconnexions modélisées à l'aide du modèle NextGrid en place, les résultats du modèle E3MC ont été utilisés pour estimer que le commerce intérieur augmenterait de 43 milliards de dollars en valeur économique au cours de la période d'analyse de 27 ans (augmentation de 17 % par rapport au scénario de référence). Étant donné que le commerce intérieur constitue un transfert entre les entités canadiennes, l'augmentation des dépenses intérieures nettes d'importation (dépenses d'importation moins revenue d'exportation) découlant du projet de règlement serait nulle dans le cadre de l'ACA, bien que des répercussions commerciales importantes et variables soient ressenties d'une province à l'autre, comme l'indique le tableau 26.

Tableau 26. Dépenses intérieures nettes supplémentaires d'importation par province (millions de dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)
T.-N.-L.	2	-31	-825	-770	-1 445	-3 068	-148
Î.-P.-É.	-0	5	61	171	118	355	17
N.-É.	-10	-52	-448	-342	-690	-1 542	-74
N.-B.	65	584	945	115	777	2 486	120
Qué.	-67	-540	337	-1 562	-2 139	-3 971	-192

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Ont.	21	430	1 552	4 143	4 613	10 759	520
Man.	-11	-408	-1 621	-1 673	-910	-4 623	-223
Sask.	-1	370	1 745	1 608	1 271	4 993	241
Alb.	73	917	3 475	4 342	7 538	16 344	789
C.-B.	-72	-1 276	-5 222	-6 033	-9 134	-21 737	-1 050
Yn.	-0	0	1	1	1	3	0
T.N.-O.	0	0	0	0	0	0	0
Nt.	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0

Pour avoir une idée de la répercussion globale du projet de règlement sur les coûts de chaque province, les économies totales pour les provinces (consommation de combustible évitée, coûts variables d'opération et de maintenance évités et mises à niveau évitées) ont été soustraites des coûts totaux pour les provinces (coûts en capital pour la nouvelle capacité du réseau électrique, coûts en capital pour les nouvelles lignes de transmission, coûts fixes d'opération et de maintenance, valeur résiduelle du capital sur les mises hors service anticipées, importations internationales nettes, importations nationales nettes et coûts administratifs) pour obtenir les coûts nets totaux par province (tableau 27). Les valeurs positives représentent les coûts nets supplémentaires pour les provinces, tandis que les valeurs négatives représentent les économies nettes supplémentaires pour les provinces. Normalisées par le PIB provincial, les provinces qui subiraient les coûts nets les plus élevés sont le Nouveau-Brunswick, la Saskatchewan et l'Alberta, tandis que les provinces qui réaliseraient les économies nettes les plus importantes sont la Colombie-Britannique et Terre-Neuve-et-Labrador.

Tableau 27. Coûts différentiels nets des économies différentielles par province (en millions)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total sur 27 ans	Moyenne annualisée (n=27)	Mesure du coût relatif en fonction de la taille de l'économie *
T.-N.-L.	2	28	-273	-627	-95	-964	-47	-1 190
Î.-P.-É.	0,0	80	50	167	116	412	20	2 419
N.-É.	1 672	3 584	-313	-71	-1 695	3 177	153	3 089
N.-B.	49,1	531	1 986	4 774	1 037	8 377	405	9 910
Qué.	4	176	-318	-579	-478	-1 194	-58	-118
Ont.	-60	5 579	9 896	481	3 457	19 353	935	968
Man.	1	425	-286	-115	329	353	17	210
Sask.	346	2 416	3 687	1 155	3 600	11 204	541	5 292
Alb.	2 642	17 010	4 061	5 064	5 918	34 694	1 675	3 906
C.-B.	-58,2	1 109	-4 562	-5 303	-8 034	-16 848	-814	-2 404
Yn.	0	0	1	1	1	3	0	31
T.N.-O.	0	0	-2	-2	-2	-6	0	-51
Nt.	0	0	0	0	0	0	0	-0,4
Total	4 598	30 938	13 928	4 944	4 154	58 561	2 828	s.o.

* Les valeurs de cette colonne ont été calculées en divisant les coûts nets moyens annualisés pour les provinces (en dollars) par la contribution projetée de chaque province au PIB du Canada (en millions de dollars) en 2023 (l'année de base de l'actualisation dans l'ACA), comme estimée par E3MC. Les valeurs dans les colonnes n'ont de sens que lorsqu'elles sont comparées les unes aux autres pour indiquer un positionnement relatif, mais n'ont pas d'interprétation réelle si elles sont considérées en isolation.

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Analyse des tarifs d'électricité

De façon générale, les tarifs d'électricité résidentiels se composent d'une partie fixe et d'une partie variable. La partie fixe prend en compte l'investissement en capital tandis que la partie variable prend en compte les coûts de production. Aux fins de l'ACA, on suppose que la majorité des coûts encourus par les compagnies d'électricité seront finalement répercutés sur les consommateurs par le biais de ce mécanisme de tarification, d'une manière qui est spécifique à chaque province (étant donné que les tarifs d'électricité relèvent de la politique provinciale et sont déterminés au niveau provincial). Dans la plupart des cas, on s'attend à ce que les investissements dans des technologies de production peu ou non émettrices augmentent la partie fixe de la facture d'électricité d'un ménage et diminuent la partie variable. Lorsque, selon les approches de tarification déterminées par la province, les augmentations des tarifs fixes sont appliquées de manière égale à tous les consommateurs, quelle que soit leur consommation d'électricité, les ménages à faible revenu paieraient une proportion plus élevée de leur revenu pour couvrir ces coûts par rapport aux ménages à revenu plus élevé.

En vertu du projet de règlement, bien que les coûts variables de production diminueraient pour plusieurs provinces, la plupart des provinces devraient d'abordes entreprendre d'importants investissements en capital pour construire de nouvelles capacités de production d'électricité peu ou non émettrices et de nouvelles lignes de transmission. Comme ce serait généralement le cas pour couvrir les coûts des immobilisations, ces investissements seraient financés et remboursés aux prêteurs, répartissant ainsi les paiements effectués sur ce capital au fil du temps.

Le modèle E3MC a été utilisé pour modéliser l'impact que le projet de règlements pourrait avoir sur les tarifs d'électricité pour différents segments de l'économie au fil du temps. Ces tarifs sont générés par le modèle E3MC de manière endogène, à l'aide d'une formule complexe qui utilise les résultats d'autres variables modélisées telles que les achats, les ventes, les importations, les exportations, les crédits et les taxes liés à l'énergie, ainsi que les coûts non liés à l'électricité. Il convient de noter que les tarifs d'électricité résidentiels générés par le modèle E3MC ne prennent pas en compte les formules de fixation des tarifs propres à chaque province, comme les plafonds tarifaires qui peuvent exister dans certaines provinces. Ainsi, les impacts tarifaires modélisés par le modèle E3MC peuvent éventuellement surestimer l'amplitude des augmentations ou des baisses de tarifs. En fin de compte, le coût du réseau électrique dans chaque province et l'impact de ce réseau sur les tarifs seront le reflet des décisions prises au niveau provincial en réponse au projet de règlement, qui peuvent varier par rapport aux impacts modélisés par le modèle E3MC. Il est également important de noter que la modélisation des tarifs dans le modèle E3MC ne fait pas la différence entre les changements apportés à la partie à taux fixe d'une facture d'électricité et ceux apportés à la partie à taux variable. Par conséquent, les augmentations de tarifs modélisées par le modèle E3MC représentent les augmentations moyennes des factures d'électricité dans les deux dimensions, présentées par kWh.

Dans le scénario de référence, la construction de nouvelles infrastructures (et l'exploitation de ce réseau électrique modélisé) aurait été associée à des augmentations moyennes des tarifs réels de l'électricité résidentielle de 43 % entre 2025 et 2050 cumulés. En revanche, dans le scénario réglementaire, la construction de nouvelles infrastructures (et l'exploitation de ce réseau électrique modélisé) serait associée à des augmentations moyennes des tarifs réels d'électricité résidentielle de 45 % entre 2025 et 2050 cumulés. La variation différentielle des tarifs réels de l'électricité résidentielle (c'est-à-dire la variation des tarifs attribuable au projet de règlement) n'est que la différence de tarifs entre le scénario de référence et le scénario réglementaire. Les répercussions alternatives sur les tarifs suivant une méthodologie différente de celle du cas central sont explorées dans l'analyse de sensibilité. L'analyse de sensibilité explore les coûts ayant une incidence sur les taux qui découlent d'une approche de modélisation différente de celle utilisée dans le cadre de la modélisation du cas central.

En vertu du projet de règlement, la modélisation à l'aide du modèle E3MC estime que les tarifs résidentiels moyens nationaux (en dollars constants non actualisés de 2022) augmenteraient par rapport au scénario de référence de 0,08 cent le kWh en 2035 (augmentation de 0,35 %), de 0,49 cent le kWh en 2040 (augmentation de 1,9 %), de 0,35 cent le kWh en 2045 (augmentation de 1,2 %) et 0,26 cent le

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kWh en 2050 (augmentation de 0,89 %). La majorité des provinces et des territoires devraient connaître des augmentations de taux bien inférieures à la moyenne nationale, certains affichant des réductions de taux par rapport au niveau de référence. Cependant, pour les provinces qui comptent actuellement davantage sur les technologies émettrices pour produire de l'électricité, des augmentations tarifaires supplémentaires plus importantes sont prévues. Par exemple, en 2040, la modélisation à l'aide du modèle E3MC estime que les tarifs résidentiels augmenteraient par rapport au scénario de référence de 3,9 cents le kWh en Nouvelle-Écosse (augmentation de 15 %), de 1,2 cents le kWh en Alberta (augmentation de 5 %), de 0,9 cent le kWh en Saskatchewan (augmentation de 3 %) et de 0,4 cent le kWh au Nouveau-Brunswick (augmentation de 2 %). La modélisation à l'aide du modèle E3MC suggère que d'ici 2050, les impacts différentiels des tarifs diminueront à l'échelle nationale par rapport au sommet atteint en 2040. Par exemple, en 2050, la modélisation à l'aide du modèle E3MC estime que les tarifs résidentiels augmenteraient de 2,6 cents le kWh par rapport au scénario de référence en Nouvelle-Écosse (augmentation de 9 %), 1,2 cent le kWh en Alberta (augmentation de 4 %) et 1,1 cents le kWh en Saskatchewan (augmentation de 3 %), tandis que les tarifs résidentiels diminueraient par rapport au scénario de référence de 1,2 cents le kWh (diminution de 4 %) au Nouveau-Brunswick.

Pour mettre en contexte ces changements de tarifs résidentiels modélisés, la maison individuelle moyenne a consommé 12 555 kWh d'électricité en 2019, tandis que l'appartement moyen dans une tour d'habitation a consommé 7 222 kWh d'électricité.[33] En maintenant ces utilisations constantes et en les utilisant pour former une fourchette illustrative, les paiements annuels moyens nationaux d'électricité au niveau résidentiel pourraient culminer à une augmentation de 35 $ à 61 $ par ménage en 2040. Cependant, par rapport au niveau de référence, les paiements annuels moyens nationaux d'électricité ne devraient être que de 19 $ à 33 $ de plus par ménage en 2050. Il est important de noter que de tels changements dans les paiements nationaux moyens annuels d'électricité s'ajouteraient aux autres augmentations prévues dans le scénario de référence. Comme c'est le cas avec les taux différentiels indiqués ci-dessus, les provinces qui dépendent actuellement davantage des technologies émettrices pour produire de l'électricité devraient connaître des augmentations plus importantes des paiements annuels d'électricité par rapport au niveau de référence, qui culmineraient en 2040, mais diminueraient quelque peu pour la plupart des provinces d'ici 2050. Par exemple, les paiements d'électricité supplémentaires annuels moyens au niveau résidentiel pourraient être de 279 $ à 485 $ plus élevés en Nouvelle-Écosse en 2040 par rapport au niveau de référence, mais seulement de 185 $ à 322 $ plus élevés en 2050. En 2040, alors que ces paiements devraient être de 88 $ à 154 $ de plus en Alberta par rapport au niveau de référence, mais seulement de 86 $ à 149 $ de plus en 2050. En 2040, ces paiements devraient être de 32 $ à 55 $ plus élevés au Nouveau-Brunswick par rapport au niveau de référence (conformément à la moyenne nationale), mais seraient de 88 $ à 153 $ de moins que le niveau de référence en 2050. En 2040, ces paiements devraient être supérieurs de 64 $ à 111 $ par rapport au niveau de référence en Saskatchewan et de 79 $ à 137 $ de plus en 2050.

La modélisation à l'aide du modèle E3MC estime que les changements aux tarifs commerciaux et industriels dans chaque province suivraient un schéma et une ampleur similaires à ceux des tarifs résidentiels (c'est-à-dire une augmentation de 2,2 % pour les tarifs commerciaux et de 2,8 % pour les tarifs industriels en 2040, et une augmentation de 1,1 % pour les tarifs commerciaux et de 1,3 % pour les tarifs industriels en 2050).

Alors que le projet de règlement devrait entraîner une augmentation des tarifs de l'électricité par rapport au scénario de référence, ces augmentations doivent être comprises dans le contexte des budgets énergétiques globaux, qui devraient être considérablement influencés par l'ensemble des mesures mises en place pour soutenir l'électrification propre de l'économie. Par exemple, bien que les ménages puissent subir des augmentations de tarifs d'électricité, ils devraient également réaliser des économies et bénéficier d'une plus grande certitude en matière de prix lorsqu'ils passeront de combustibles fossiles de plus en plus coûteux à de l'électricité propre pour chauffer et climatiser leurs maisons et pour faire fonctionner leurs véhicules. Comme le souligne le Canadian Climate Institute : l'augmentation de la

[33] Statistique Canada (Table 25-10-0061-01): Consommation d'énergie des ménages, par type de logement, Canda et les provinces

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consommation d'électricité des ménages correspondra à une diminution de la consommation d'essence, de gaz naturel et d'autres combustibles fossiles. Alors que les dépenses en électricité augmenteront probablement, les dépenses totales en énergie diminueront.[34] Bien que l'évaluation de l'impact d'une série complète de mesures sur les budgets énergétiques globaux des ménages soit hors de portée de l'ACA, cet aspect est exploré dans la section *Analyse comparative entre les sexes plus*.

Analyse de la demande d'électricité des ménages

La demande d'électricité des ménages et, par extension, le rythme auquel les ménages sont censés s'électrifier, peuvent être affectés par les modifications des tarifs de l'électricité résidentielle induites par le projet de règlement. En réponse à des prix de l'électricité plus élevés, les consommateurs peuvent modifier leur comportement au fil du temps pour réduire la quantité d'électricité qu'ils utilisent. Par exemple, certains ménages peuvent réagir en investissant dans des technologies et des maisons plus efficaces sur le plan énergétique. D'autres ménages peuvent réagir en remplaçant l'électricité par d'autres sources d'énergie. Certains ménages peuvent également réagir en réduisant la quantité d'activités dépendantes de l'électricité auxquelles ils participent (ou en réduisant le nombre d'heures consacrées à ces activités). Les changements de comportement particuliers qu'un ménage entreprendrait dépendent de nombreux facteurs tels que l'élasticité de la demande par rapport au prix (la sensibilité de la consommation d'électricité des ménages au prix), le prix et la disponibilité de sources d'énergie de substitution et les préférences individuelles.

Les résultats du modèle E3MC ont été utilisés pour évaluer les répercussions potentielles du projet de règlements sur la demande d'électricité des ménages et l'électrification. Le tableau 28 présente la demande totale d'électricité résidentielle en tant que proportion de la demande totale d'énergie résidentielle dans le scénario de référence par rapport au scénario réglementaire pour certaines années.

Tableau 28. Demande totale d'électricité résidentielle en proportion de la demande totale d'énergie résidentielle, scénario de référence par rapport au scénario réglementaire pour certaines années

Province	Proportion du scénario de référence (2025)	Proportion du scénario réglementaire (2025)	Proportion du scénario de référence (2050)	Proportion du scénario réglementaire (2050)
T.-N.-L.	30,0 %	30,0 %	37,2 %	37,2 %
Î.-P.-É.	12,1 %	12,1 %	33,6 %	33,7 %
N.-É.	25,7 %	25,7 %	52,1 %	51,0 %
N.-B.	34,9 %	34,9 %	50,3 %	50,6 %
Qué.	42.7%	42.7%	75.1%	75.0%
Ont.	16,9 %	16,9 %	29,5 %	29,4 %
Man.	30.5%	30.5%	44.9%	44.8%
Sask.	10,9 %	10,9 %	14,9 %	14,7 %
Alb.	12,8 %	12,8 %	22,5 %	22,0 %
C.-B.	23,8 %	23,8 %	44,5 %	44,4 %
Yn.	19,7 %	19,7 %	50,3 %	50,3 %
T.N.-O.	7,7 %	7,7 %	11,4 %	11,4 %
Nt.	6,5 %	6,5 %	9,2 %	9,2 %
Moyenne	21,1 %	21,1 %	36,6 %	36,4 %

Comme le montre le tableau 28, l'électrification au niveau des ménages devrait être importante dans le scénario de référence, on s'attend à ce que la demande en électricité des ménages double par rapport à

[34] Source: L'Institut Climatique du Canada - L'électricité et l'équité dans la transition Énergétique du Canada p.4.

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la demande totale d'énergie entre 2025 et 2050 dans plusieurs provinces. Ces proportions sont presque identiques entre le scénario de référence et le scénario réglementaire, ce qui indique que le projet de règlement n'aurait pas de répercussions significatives sur le rythme auquel les ménages devraient s'électrifier. En effet, dans le cadre du projet de règlement, le modèle E3MC estime que la demande nationale d'électricité résidentielle ne diminuerait que d'environ 1 000 GWh en 2050 (soit une baisse d'environ 0,4 % par rapport à la demande d'électricité de référence cette année-là). Ainsi, la substitution n'est pas considérée comme une source de préoccupation dans l'analyse et toutes répercussions potentielles sur le bien-être des consommateurs et les émissions de GES qui pourraient être associées à ces changements mineurs de comportement n'ont pas été évaluées dans l'ACA.

Analyse de sensibilité

Le ministère a effectué une analyse de sensibilité en deux parties sur le projet de règlement en utilisant son modèle NextGrid, ainsi qu'une troisième partie comparant les principaux coûts d'entrée utilisés entre NextGrid et E3MC. La première partie évalue les répercussions qu'une demande d'électricité plus élevée aurait sur les combinaisons de réseaux électriques provinciaux, les émissions et les coûts totaux. La deuxième partie étudie l'effet de la modification de divers aspects de la conception du REP, notamment le niveau de la norme de rendement , les dispositions relatives à la flexibilité en fonction de la masse et de la durée, le seuil de capacité de production d'électricité, l'inclusion des groupes industriels et la fin de vie réglementaire. Dans tous les cas, le scénario réglementaire est comparé à un scénario de référence qui inclut une augmentation de la demande de 1,4 fois par rapport à la demande actuelle d'ici 2050 et toutes les politiques annoncées, à l'exception de celles annoncées dans le budget 2023, pour le secteur de l'électricité (*le Règlement modifiant le Règlement sur la réduction des émissions de dioxyde de carbone — secteur de l'électricité thermique au charbon*, *le Rrèglement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel* et la tarification de la pollution par le carbone telle qu'elle s'applique à la production d'électricité par le biais du *Règlement sur le système de tarification fondé sur le rendement*, ou STFR). La comparaison est effectuée pour le scénario de faible demande, modélisé comme une augmentation de 1,4 fois (« 1,4 X ») par rapport à la demande actuelle d'ici 2050 et utilisé dans l'ACA, et pour le scénario de forte demande, modélisé comme une augmentation de 2,5 fois (« 2,5 X ») par rapport à la demande actuelle d'ici 2050. Étant donné que cette analyse de sensibilité sur le projet de règlement a été réalisée à l'aide du modèle NextGrid, ces résultats ne peuvent pas être combinés avec les résultats présentés dans l'ACA, qui utilise le modèle E3MC.

Partie 1

Changements dans la combinaison des technologies déployées pour répondre à la demande

Le Canadian Climate Institute a récemment passé en revue une série d'études qui estiment que la réalisation d'une économie carboneutre nécessitera une augmentation de la production globale d'électricité de 1,6 à 2,1 fois d'ici 2050 par rapport au niveau de 2020. D'autres études avaient précédemment estimé que la demande d'électricité triplerait d'ici 2050. Compte tenu de la difficulté de prévoir avec précision l'augmentation future de la demande d'électricité, le ministère a choisi d'évaluer les sensibilités à l'aide d'une approche « à deux volets » qui évalue les résultats pour un scénario de demande faible et un scénario de demande élevée, conformément à ces travaux indépendants. Dans ce contexte, l'augmentation de la demande de 2,5 (« 2,5 X ») représente une estimation prudente et élevée qui vise à saisir toute l'augmentation de la demande d'électricité qui serait observée dans le cadre d'une économie carboneutre. À l'inverse, le scénario de faible demande (« 1,4 X ») suppose une croissance modeste de l'électrification d'autres secteurs, ce qui signifie qu'une plus grande part de l'approvisionnement énergétique dans le cadre de la décarbonisation provient de sources autres que l'électricité, par exemple l'hydrogène. L'augmentation réelle de la demande au Canada dépendra de la mesure dans laquelle les Canadiens finiront par compter sur l'électricité propre pour la décarbonisation de l'ensemble de l'économie d'ici à 2050. Une forte dépendance à l'égard de l'électricité propre, c'est-à-

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dire une augmentation élevée de la demande, entraînera un besoin accru de capacités de production d'électricité non émettrice d'ici 2050, tandis qu'une faible dépendance à l'égard de l'électricité propre, c'est-à-dire une faible croissance de la demande, entraînera probablement un déploiement relativement moins important de capacités non émettrices. Cela aurait non seulement des répercussions sur la capacité et le mix de production dans le secteur de l'électricité en 2050, mais aussi sur les coûts qui en résulteraient pour les producteurs et les consommateurs. Ces répercussions devraient donc être examinées dans le cadre de cette analyse des impacts du REP.

Le modèle NextGrid a été utilisé pour projeter la combinaison des options d'approvisionnement qui seraient déployées d'ici 2050 pour répondre au scénario de croissance de la charge utilisé dans l'analyse coûts-avantages (c'est-à-dire 1,4 fois la demande actuelle) et l'a comparée à la combinaison qui résulterait d'un scénario de 2,5 fois la demande, qui est similaire aux projections de croissance de la demande figurant dans la littérature récente[35]. Cette évaluation de la composition du réseau électrique a été réalisée pour l'ensemble du Canada, ainsi que pour l'Alberta, la Saskatchewan, l'Ontario, la Nouvelle-Écosse et le Nouveau-Brunswick, car ce sont les provinces qui disposent actuellement d'une importante capacité de production d'électricité à partir de combustibles fossiles qui serait assujettie au projet de règlement. En comparant les combinaisons de réseaux électriques du scénario 2,5 X à celles du scénario 1,4 X, il semblerait qu'en vertu du projet de règlement, les mêmes technologies seraient, en général, déployées quel que soit le scénario de demande, mais qu'une plus grande capacité serait déployée dans le scénario de charge plus élevée. Il en résulte un réseau électrique plus propre par MWh, car les nouveaux déploiements sont en grande partie des groupes peu ou non émetteurs. C'est le résultat attendu, car NextGrid optimise le coût le plus bas sur la base des technologies déployées (c'est-à-dire que la solution optimale des technologies déployées s'adapte à l'échelle des besoins pour les mêmes technologies). La même relation est observée pour la production.

Changements dans les émissions totales

En passant d'un scénario dans lequel le projet de règlement réglemente les émissions liées à la satisfaction d'une demande de 1,4 fois la demande actuelle à un scénario dans lequel la demande est de 2,5 fois la demande actuelle, on s'attendrait à voir plus d'émissions dans le scénario 2,5 fois la demande actuelle. C'est le résultat attendu puisque, même si le projet de règlement réduit considérablement les émissions de chaque groupe, un plus grand nombre de groupes est nécessaire pour répondre à une plus grande demande et, par conséquent, il y a plus d'émissions au niveau juridictionnel. Cette tendance attendue est généralement observée dans l'analyse de sensibilité, résumée dans le tableau 29. Dans l'ensemble, on s'attend à ce que le projet de règlement soit aussi efficace dans un scénario 2,5 X qu'il le serait dans un scénario 1,4 X. Cela s'explique en grande partie par le fait que le modèle NextGrid prévoit que la demande accrue serait principalement satisfaite par une production non émettrice dont la nature variable est stabilisée par une combinaison d'échanges interprovinciaux accrus d'électricité, de stockage d'énergie, de réponse à la demande et de production à base de combustibles fossiles rarement utilisée. Des différences sont toutefois observées au niveau provincial. Notamment, le Québec et la Nouvelle-Écosse verraient des réductions plus importantes dans le cadre d'un scénario 2,5 X que dans le cadre d'un scénario 1,4 X. Étant donné que cette analyse de sensibilité sur le projet de règlement a été réalisée à l'aide du modèle NextGrid, ces résultats ne peuvent pas être combinés avec les résultats présentés dans l'ACA, qui utilise le modèle E3MC. Le scénario 1,4 X a été fourni ici pour servir de point de référence aux résultats du scénario 2,5 X.

Tableau 29. Variation en pourcentage des émissions totales dans le cadre du projet de règlement pour un scénario d'augmentation de la demande de 1,4 X et de 2,5 X

[35] Plus grands, plus propres, plus intelligents. Aligner les systèmes électriques canadiens avec la carboneutralité

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Juridiction	Pourcentage de variation des émissions dans le projet de règlement — scénario 1,4 X par rapport au scénario de référence (2025-2050)	Pourcentage de variation des émissions dans le projet de règlement — scénario 2,5 X par rapport au scénario de référence (2025-2050)
CAN	-28%	-32%
C.-B.	-10 %	-9 %
Alb.	-26 %	-27 %
Sask.	-38 %	-38 %
Man.	-55%	-38%
Ont.	-35 %	-40 %
Qué.	-39%	-70%
N.-B.	-10 %	-1 %
N.-É.	-1 %	-71 %
T.-N.-L.	-9 %	-9 %
Î.-P.-É.	0 %	-0 %

Changements dans les coûts totaux

La variation en pourcentage des coûts totaux en vertu du projet de règlement pour un scénario d'augmentation de la demande de 1,4 X et de 2,5 X est résumée dans le tableau 30. Étant donné les coûts inférieurs de la production non émettrice, de la transmission et de la réponse à la demande par rapport à la production émettrice réduite, NextGrid prévoit que les scénarios avec une demande plus élevée verraient une part disproportionnée de cette demande satisfaite par des sources non émettrices. Ainsi, les augmentations proportionnelles des coûts par rapport au scénario de référence pour le scénario de demande plus faible sont à peu près constantes par rapport à celles du scénario de demande plus élevée. Étant donné que cette analyse de sensibilité sur le projet de règlement a été réalisée à l'aide du modèle NextGrid, ces résultats ne peuvent pas être combinés avec les résultats présentés dans l'ACA, qui utilise le modèle E3MC. Le scénario 1,4 X a été fourni ici pour servir de point de référence aux résultats du scénario 2,5 X.

Tableau 30. Pourcentage de variation des coûts totaux dans le cadre du projet de règlement pour un scénario d'augmentation de la demande de 1,4 X et 2,5 X

Juridiction	Pourcentage de variation des émissions dans le projet de règlement — scénario 1,4 X par rapport au scénario de référence (2025-2050)	Pourcentage de variation des émissions dans le projet de règlement — scénario 2,5 X par rapport au scénario de référence (2025-2050)
CAN	5%	4%
C.-B.	3 %	1 %
Alb.	4 %	2 %
Sask.	7 %	4 %
Man.	8%	3%
Ont.	6 %	4 %
Qué.	4%	5%
N.-B.	2 %	0 %
N.-É.	4 %	3 %
T.-N.-L.	4 %	13 %

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Î.-P.-É.	7 %	3 %

Les prix moyens de l'électricité ont été calculés à partir des résultats des coûts du modèle NextGrid en y incorporant les coûts de la dette du service public, les coûts de distribution et de transmission et d'autres considérations relatives aux coûts finaux supportés par les consommateurs. Ces prix moyens tiennent compte des tarifs volumétriques de l'électricité et des charges fixes.

Sur la base des résultats des coûts du modèle NextGrid pour le scénario 1,4 X, les prix moyens calculés de l'électricité augmentent de 0,7 cent par kWh (4,0 %) en 2035 et de 0,7 cent par kWh (4,0 %) en 2050, exprimés en tant que moyenne simple au niveau national et par rapport à la base de référence. Des augmentations relatives faibles et similaires des prix moyens de l'électricité sont également observées dans le scénario 2,5 X, les prix de l'électricité augmentant de 0,6 cent par kWh (4,0 %) en 2035 et de 0,3 cent par kWh (1,0 %) en 2050. Comme pour les résultats de l'étude E2020 dans le cadre d'un scénario de croissance de 1,4 X, la plupart des provinces affichent de faibles variations des prix de l'électricité résidentielle par rapport au scénario de référence, bien que certaines provinces affichent des répercussions plus importantes sur les prix de l'électricité par rapport au scénario de référence (Nouvelle-Écosse, Île-du-Prince-Édouard et Terre-Neuve-et-Labrador).

Étant donné que les conclusions ci-dessus reposent sur la moyenne arithmétique des différences entre les prix de l'électricité dans le scénario réglementaire et le scénario de référence sur les dix provinces, la moyenne nationale qui en résulte considère que le volume d'électricité dans chaque province est égal. Ce n'est pas le cas dans la réalité, car la consommation varie considérablement d'une province à l'autre. Si le prix moyen national de l'électricité est pondéré par la consommation, la moyenne pondérée qui en résulte donne une idée plus précise des répercussions du projet de règlement au niveau national. Les résultats de la moyenne pondérée indiquent une augmentation des prix de 0,3 cent par kWh (2,2 %) en 2035 et de 0,1 cent par kWh (0,8 %) en 2050 pour le scénario 1,4 X. Pour le scénario 2,5 X, l'augmentation est de 0,1 cent par kWh en 2035 et de 0,1 cent par kWh en 2050. Pour le scénario 2,5 X, les augmentations de prix sont à peu près les mêmes.

Une analyse plus approfondie pour comprendre ces répercussions est en cours sur les résultats des données du modèle E2020 et du modèle NextGrid afin de s'assurer que des conclusions solides sont tirées en tenant compte d'une gamme de résultats en matière de coûts.

Conclusions générales

Par rapport aux scénarios de demande plus faible, on peut s'attendre à ce que le projet de règlement, dans des scénarios de demande plus élevée, permette :

- de contribuer à produire des réseaux électriques avec les mêmes types de technologies non émettrices ;
- d'être aussi efficaces en termes de réduction des émissions ; et
- de présenter des différences de coût total similaires (en pourcentage) par rapport au scénario de référence.

Partie 2

La deuxième partie de l'analyse de sensibilité évalue les incidences sur les coûts et les réductions d'émissions qui résulteraient du renforcement ou de l'assouplissement des éléments suivants du projet de règlement :

1. **Norme de rendement :** La valeur proposée est de 30 t/GWh ; l'analyse de sensibilité envisage 0 t/GWh et 100 t/GWh ;

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2. **Groupes fonctionnant dans le cadre de la flexibilité des émissions/durée basée sur la masse :** Il est proposé que la contribution à la production de ces groupes dans le cadre de la flexibilité des émissions/durée basée sur la masse soit contrainte aux limites annuelles de 450 heures (ce qui équivaut approximativement à une utilisation de 5 %) et de 150 kt d'émissions. L'analyse de sensibilité envisage : i) de ne permettre aucune utilisation de cette flexibilité de sorte que la fiabilité doit être assurée par des options n'utilisant pas de combustibles fossiles et ii) d'autoriser une utilisation jusqu'à 10 % ;

3. **Seuil de capacité de production d'électricité :** La valeur proposée est de 25 MW ; l'analyse de sensibilité porte sur 2,5 MW et 50 MW. Par souci de clarté, seuls les groupes dont la capacité est supérieure au seuil seraient soumis au projet de règlement ;

4. **Traitement des groupes industriels :** L'approche proposée n'obligerait que les groupes industriels qui ont un solde exportateur supérieur à zéro gigawattheure vers un réseau électrique réglementé par la NERC au cours d'une année donnée à se conformer à la norme de rendement. L'analyse de sensibilité considère une approche dans laquelle toute la production industrielle est soumise au projet de règlement et une approche dans laquelle aucune production industrielle n'est soumise au projet de règlement : et,

5. **Durée de vie réglementaire :** La valeur proposée est de 20 ans ; l'analyse de sensibilité envisage 0, 15, 25, 30, 35, 40 et 45 ans.

La sensibilité de chacun des paramètres ci-dessus a été évaluée en exécutant le modèle NextGrid avec le projet de règlement en ne modifiant qu'un seul des paramètres ci-dessus à la fois. Les incidences sur les coûts et les émissions sont présentées sous forme de pourcentage de changement par rapport au projet de règlement. Plus précisément :

L'effet sur le coût du projet de règlement est présenté comme suit :

$$AS_C = \frac{\left(C^2_{Réglementaire} - C_{SdR}\right) - \left(C^1_{Réglementaire} - C_{SdR}\right)}{\left(C^1_{Réglementaire} - C_{SdR}\right)} \qquad \text{Eq. 1}$$

où C_{SdR}, $C^1_{réglementaire}$ et $C^2_{réglementaire}$ représentent les coûts cumulés (2025 à 2050) actualisés du scénario de référence, du scénario réglementaire et du scénario réglementaire modifié, respectivement.

L'effet sur les réductions d'émissions est calculé comme suit :

Eq2.

$$AS_E = \frac{\left(E^2_{Réglementaire} - E_{SdR}\right) - \left(E^1_{Réglementaire} - E_{SdR}\right)}{\left(E^1_{Réglementaire} - E_{SdR}\right)}$$

où E_{SdR}, $E^1_{Réglementaire}$ et $E^2_{Réglementaire}$ représentent les émissions cumulées (2025 à 2050) de la production d'électricité dans le scénario de référence, le scénario réglementaire et le scénario réglementaire modifié, respectivement.

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Les mises en garde suivantes sont importantes pour l'examen des résultats de la sensibilité :

- Les coûts sont cumulés, actualisés (en utilisant un facteur d'actualisation de 3 % contre 2 % dans l'ACA) et annualisés. Le facteur d'actualisation de 3 % a été utilisé pour évaluer les répercussions sur les combinaisons de réseaux qui en résultent (c'est-à-dire la combinaison observée des diverses sources de production qui alimentent un réseau électrique réglementé par la NERC) et il s'est avéré qu'il n'avait pas d'effet perceptible. Bien qu'ils aient une large portée (ils incluent le coût des nouveaux capitaux, du combustible, des opérations et de la maintenance fixes [FOM], des opérations et de la maintenance variables [VOM], du carbone, de la valeur résiduelle du capital en cas de production anticipée et des coûts d'intégration des énergies renouvelables variables [ERV]), ils excluent un certain nombre d'éléments : le coût de la transmission intraprovinciale, de la distribution, du financement et tout coût en capital associé aux actifs déjà construits en 2022 ; et

- Les résultats supposent que les groupes qui doivent se conformer à la limite d'intensité des émissions en vertu du projet de règlement sont pleinement exposés au prix du carbone (170 $/tonne d'équivalent CO_2) à partir de 2035.

- Étant donné que cette analyse de sensibilité sur le projet de règlement a été réalisée à l'aide du modèle NextGrid, ces résultats ne peuvent pas être combinés avec les résultats présentés dans l'ACA, qui utilise le modèle E3MC.

Effets de la variation de la rigueur de la norme de rendement

Le projet de règlement exigerait que les groupes respectent, à quelques exceptions près, une norme de rendement de 30 t/GWh. Afin d'évaluer la sensibilité des coûts et des réductions d'émissions prévus par le projet de règlement, cette norme de rendement a été évaluée à 0 t/GWh (c'est-à-dire, équivalant à une interdiction de facto des centrales à combustibles fossiles à la fin de leur vie réglementaire), ne permettant pas à ces groupes de fournir des services d'appoint pour les énergies renouvelables variables ou d'installer le CSC ; et 100 t/GWh (ce qui éviterait au projet de règlement de prévoir un délai pour que les nouveaux groupes CSC s'adaptent à la norme rigoureuse de 30 t/GWh, c'est-à-dire que 100 t/GWh sur une base annuelle moyenne est facilement réalisable par n'importe quel groupe CSC).

L'approche plus stricte de 0 t/GWh s'est avérée augmenter les coûts de 20 % et 18 % pour les scénarios 1,4 X et 2,5 X respectivement, tout en augmentant les réductions d'émissions d'environ 2 % et 3 % dans les mêmes scénarios de demande respectifs. Cette approche plus stricte ne semble donc pas être une approche rentable pour les réductions supplémentaires. L'approche moins stricte d'une norme de rendement de 100 t/GWh ne réduirait pas considérablement les coûts prévus (4 % et 5 % de réduction pour les scénarios 1,4 X et 2,5 X respectivement) et augmenterait potentiellement les émissions d'environ 12 % pour chacun des scénarios 1,4 X et 2,5 X). Cette analyse de sensibilité suggère que la norme de rendement proposée de 30 t/GWh permet de réduire les émissions sans augmenter considérablement les coûts.

Effets de la variation de la durée des dispositions relatives à la flexibilité des émissions basées sur la masse/durée

Le projet de règlement prévoit des exceptions à la norme de rendement de 30 t/GWh pour les groupes qui fonctionnent moins de 450 heures par an et émettent moins de 150 kt/an. À titre de référence, 450 heures par an correspondent à environ 5 % du total des heures d'une année en supposant un fonctionnement à 100 % de la capacité. Cette approche fournit un outil important aux entités réglementées pour préserver la fiabilité du réseau électrique en utilisant des groupes qui remplissent ces conditions pour fournir une énergie d'appoint ou de pointe et à des coûts potentiellement inférieurs si l'autre moyen de produire cette énergie de fiabilité consistait à construire de nouveaux projets d'investissement. Afin d'évaluer la sensibilité des coûts et des réductions d'émissions prévus par le projet

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de règlement, cette souplesse en matière d'émissions et de durée fondée sur la masse a été évaluée à 0 % d'utilisation (ce qui équivaut à ne pas permettre à ces groupes de fournir des services d'appoint pour les énergies renouvelables variables) et à 10 % ; aux fins de l'analyse, on a supposé que les groupes qui utilisaient cette souplesse fonctionnaient à 100 % de leur capacité. Une évaluation supplémentaire a été réalisée pour déterminer les répercussions d'une utilisation de 8 %.

L'approche plus stricte de 0 % d'utilisation s'est avérée augmenter les coûts de 12 % et 33 % pour les scénarios 1,4 X et 2,5 X respectivement, tout en augmentant les réductions d'émissions d'environ 11 % dans les deux scénarios de demande. Cela semble indiquer que la recherche de nouvelles réductions d'émissions en limitant l'utilisation des groupes émetteurs pour fournir une alimentation d'appoint/de pointe à moins de 450 heures n'apporterait pas de nouvelles réductions, tandis que les coûts continueraient d'augmenter avec l'accroissement de la demande d'électricité. Cette conclusion suggère que 450 heures est probablement la valeur minimale à prendre en compte. Dans ce contexte, les analyses ont indiqué que l'approche moins stricte d'un facteur d'utilisation de 10 % ne réduirait pas considérablement les coûts prévus (3 % et 1 %, respectivement, pour les scénarios 1,4 X et 2,5 X) et entraînerait une perte proportionnellement plus élevée de réductions d'émissions (6 % et 15 %, respectivement, pour les scénarios 1,4 X et 2,5 X). L'évaluation d'une utilisation de 8 % pour le scénario de demande 1,4 X a indiqué une réduction des coûts de seulement 2 % par rapport à 450 heures et une perte de réductions d'émissions d'environ 4 %. Cette analyse de sensibilité suggère que les valeurs proposées de 450 heures et 150 kt fournissent le meilleur équilibre entre les économies de coûts et les réductions d'émissions.

Le ministère invite les parties intéressées à fournir des commentaires spécifiques, fondés sur des preuves, ainsi que toute donnée relative à cette importante flexibilité avant la publication dans la partie II de la *Gazette du Canada*. Bien que l'objectif du projet de règlement soit de réduire les émissions de CO_2 provenant de la production d'électricité, il est également important que l'approvisionnement en électricité du Canada demeure fiable et abordable, car cela contribue à la fois à la sécurité des Canadiens et à l'atteinte de l'objectif du Canada d'une économie carboneutre d'ici 2050.

Effets de la variation de la valeur du seuil de capacité de production d'électricité

Les groupes de production d'électricité à partir de combustibles fossiles qui ne dépassent pas une capacité de 25 MW ne seraient pas soumis au projet de règlement. Cette approche permet d'éviter les coûts associés aux groupes qui, historiquement, n'ont pas été une source importante d'émissions de GES au Canada, tout en offrant une certaine souplesse aux exploitants de réseaux électriques dans les endroits où l'infrastructure n'est peut-être pas suffisante. Elle permettrait également de réduire le coût cumulatif de la conformité au règlement pour les exploitants de groupes, sans pour autant sacrifier une quantité importante de réductions d'émissions de carbone.

L'effet sur le coût du projet de règlement et sur les réductions d'émissions associées a été calculé pour un seuil plus strict de 2,5 MW ainsi que pour un seuil moins strict de 50 MW.

Le seuil plus strict de 2,5 MW aurait un effet négligeable sur les coûts et les réductions d'émissions pour les deux scénarios de charge. Les faibles gains en termes de réduction des émissions (de l'ordre de 1 %) ne justifient pas l'augmentation très importante du nombre d'organismes de réglementation chargés de la mise en œuvre du règlement ni la perte de flexibilité pour les opérateurs dans les endroits où l'infrastructure du réseau électrique n'est peut-être pas suffisante.

Le seuil moins strict de 50 MW réduirait le coût du projet de règlement de 3 % tout en réduisant les réductions d'émissions d'environ 5 % pour les deux scénarios de charge. Bien que la diminution proportionnelle des coûts par rapport à la perte de réductions d'émissions soit comparable à l'approche proposée, le seuil de capacité de production plus élevé de 50 MW pourrait entraîner la construction de groupes d'une capacité légèrement inférieure à 50 MW afin d'éviter d'être soumis au projet de règlement. Bien qu'un schéma d'évitement similaire soit théoriquement possible avec la valeur proposée de 25 MW,

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on s'attend à ce qu'un parc composé de groupes de moins de 25 MW ait une plus grande inefficacité logistique qu'un parc composé de groupes de moins de 50 MW. Cette plus grande inefficacité logistique est jugée suffisante pour décourager une construction appréciable de groupes légèrement inférieurs à 25 MW. C'est pourquoi l'approche proposée d'un seuil de capacité de production d'électricité de 25 MW est considérée comme la meilleure.

Effets de la variation de la mesure dans laquelle la production industrielle est incluse dans le champ d'application du projet de règlement

Le projet de règlement s'appliquerait aux groupes industriels qui satisfont aux critères d'applicabilité, notamment le fait d'être connectés à un réseau électrique réglementé par la NERC. Toutefois, seuls les groupes qui ont un solde exportateur de plus de zéro gigawattheure au cours d'une année donnée devront se conformer à la norme de rendement . Cette approche devrait permettre d'éviter la ruée vers la production d'électricité destinée à être vendue à un réseau d'électricité réglementé par la NERC en utilisant des groupes de production d'électricité à base de combustibles fossiles sans dispositif de réduction des émissions appartenant à l'industrie ; l'approche s'appuie également sur d'autres instruments — adaptés à des secteurs industriels spécifiques — pour réduire les émissions associées à l'électricité produite uniquement pour l'activité industrielle.

La sensibilité des coûts estimés et des réductions d'émissions à l'approche proposée a été analysée pour deux couvertures alternatives des groupes industriels : une politique plus stricte dans laquelle tous les groupes industriels sont entièrement couverts, qu'ils exportent ou non vers un réseau électrique réglementé par la NERC, et une politique moins stricte dans laquelle les groupes industriels sont entièrement exemptés du respect de la norme de rendement .

Bien que les réductions d'émissions associées à cette approche plus stricte soient très élevées (105 % et 80 % plus élevées pour les scénarios de charge 1,4 X et 2,5 X, respectivement), la couverture de tous les groupes industriels de production d'électricité augmente également de manière significative le coût du projet de règlement, de 87 % et 62 % pour les scénarios de charge 1,4 X et 2,5 X, respectivement. Cette augmentation de coût ne prend en compte que le coût de la production d'électricité et de chaleur industrielle à partir de groupes de cogénération et n'évalue pas les répercussions secondaires que ces coûts pourraient avoir sur l'activité industrielle en particulier (par exemple, en supprimant potentiellement l'activité économique, en réduisant la compétitivité, etc.) et sur l'économie canadienne en général. Par conséquent, cette constatation particulière ne devrait pas être considérée comme une justification suffisante pour assujettir toute la production industrielle à la norme de rendement prévue dans le projet de règlement. Par ailleurs, le fait de ne pas assujettir la production industrielle au projet de règlement représente un scénario dans lequel la production industrielle peut vendre sans limites de l'électricité produite à partir de combustibles fossiles au réseau électrique. Cette approche ne réduirait pas de manière significative le coût du projet de règlement (2 % pour le scénario 1,4 x et 1 % pour le scénario 2,5 X), mais diminuerait les réductions d'émissions d'un montant sensiblement plus élevé : 35 % et 26 % pour les scénarios de charge 1,4 X et 2,5 X, respectivement. Cette analyse n'a pas pris en compte la possibilité que l'électricité ne soit plus produite par des groupes appartenant au service public, mais par des groupes industriels utilisant des combustibles fossiles sans dispositif de réduction des émissions ; en ne prenant pas en compte cette possibilité, la conclusion relative à la réduction des émissions perdues est probablement biaisée, c'est-à-dire que les réductions d'émissions perdues sont sous-estimées et seraient probablement plus élevées que 35 % et 26 %. Cette constatation indique que l'approche proposée dans le projet de règlement couvrant les groupes industriels ayant un solde exportateur de plus de zéro gigawattheure est probablement la meilleure des solutions envisagées, car elle est moins susceptible d'avoir des incidences économiques plus larges, mais elle permet également d'obtenir des réductions d'émissions à faible coût du point de vue de l'ensemble de l'économie.

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Effets de la variation de la fin de vie réglementaire

Le projet de règlement permet aux groupes mis en service avant le 1er janvier 2025 de continuer à fonctionner sans avoir à respecter une limite d'intensité des émissions jusqu'à la fin de la durée de vie réglementaire du groupe, que l'on propose de fixer à 20 ans, ou jusqu'au 1er janvier 2035, selon la date la plus tardive. Cette approche permet d'introduire progressivement l'activité nécessaire pour soutenir un réseau électrique carboneutre, évitant ainsi une chute brutale de la capacité en 2035 tout en garantissant que les groupes de production d'électricité à base de combustibles fossiles sans dispositif de réduction des émissions soient conformes au règlement bien avant 2050.

L'effet sur le coût du projet de règlement et sur les réductions d'émissions associées a été calculé pour une série de nombres d'années alternatifs, allant de 0 an (c'est-à-dire que les groupes existants doivent satisfaire à la norme de rendement en 2035, tout comme les nouveaux groupes) à 45 ans (c'est-à-dire que les groupes sont autorisés à fonctionner jusqu'à la fin de leur durée de vie technique).

La fixation de la durée de vie prescrite à 0, 5, 10 ou 15 ans a donné des résultats similaires : Le coût du projet de règlement dans un scénario de charge 1,4 X augmente d'environ 8 %, mais les réductions d'émissions n'augmentent que de 3 %. Pour un scénario de charge 2,5 X, l'augmentation du coût est négligeable et les réductions d'émissions n'augmentent que de 2 %. Compte tenu des difficultés logistiques accrues auxquelles on peut raisonnablement s'attendre en cas de mise en place accélérée des nouvelles capacités nécessaires pour assurer la fiabilité du réseau et du gain relativement faible en termes de réduction des émissions, il ne semble pas avantageux de réduire le nombre d'années pendant lesquelles les groupes existants peuvent fonctionner après leur mise en service.

Par contre, le fait de permettre aux groupes existants de fonctionner pendant 35 à 45 ans après la date de mise en service permet de réduire le coût du projet de règlement, mais au détriment de pertes importantes en termes de réductions d'émissions. Pour le scénario de charge 1,4 X, les coûts diminuent de 14 % à 77 % pour une durée d'exploitation de 35 à 45 ans, mais les réductions d'émissions diminuent également de 25 % à 76 %. Pour le scénario de charge 2,5 X, la diminution des coûts associée à une durée de vie prescrite de 35 à 45 ans est de 10 % à 53 %, mais aux dépens d'une réduction des émissions de 14 % à 31 %.

Un allongement plus modéré de la durée de vie prescrite (c'est-à-dire de 25 à 30 ans) est associé à une *augmentation* modérée des coûts du projet de règlement. Pour le scénario de charge 1,4 X, ces augmentations vont de 1 % à 6 % pour 25 et 30 ans, alors qu'elles vont de 4 % à 2 % pour les mêmes années dans les scénarios de charge 2,5X. Ces augmentations de coûts s'accompagnent de pertes modérées en termes de réduction des émissions : 4 % et 12 % pour 25 et 30 ans dans le scénario 1,4 X et 3 % et 7 % pour le même nombre d'années dans le scénario de charge 2,5 X.

Cela indique que la durée d'exploitation proposée de 20 ans est la meilleure option, car elle permet d'équilibrer la mise en œuvre progressive du règlement pour assurer la fiabilité, de gérer les coûts et de ne pas sacrifier une quantité substantielle de réductions d'émissions. Toutefois, si d'autres considérations, telles que des réalités logistiques limitant le rythme auquel de nouvelles capacités pourraient être mises en place, devaient être démontrées comme une préoccupation valable, des périodes de vie prescrite plus longue, ne dépassant pas 30 ans, ne devraient pas avoir d'incidences significatives sur les réductions d'émissions attendues du projet de règlement.

Troisième partie

La troisième partie de l'analyse de sensibilité teste les répercussions sur le coût total de l'utilisation de coûts d'entrée différents pour les variables clés que ceux utilisés dans la modélisation du cas central. Dans l'ACA, les coûts totaux sont sensibles à une variable en particulier : le coût marginal du capital (par MW) de la construction de nouvelles installations pour les technologies du réseau électrique (coûts marginaux du capital). Cette variable détermine l'ampleur des répercussions sur les coûts associés à la

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construction de nouvelles installations de technologies de production d'électricité avec dispositif de réduction des émissions et non émettrices, induits par le projet de règlement, mais elle affecte également l'ampleur des répercussions associées à l'abandon de la remise en état et à la valeur résiduelle du capital lors des mises hors service anticipées.

Les coûts marginaux du capital utilisés dans la modélisation du cas central ont été calculés par le modèle E3MC. Cependant, il ne s'agit pas des seules estimations des coûts du capital qui pourraient être prises en compte dans l'analyse. Dans le cadre du processus d'élaboration du modèle NextGrid, le ministère a chargé un contractant externe de compiler, entre autres, une projection des coûts marginaux du capital pour les technologies clés du réseau électrique dans chaque province en utilisant des informations provenant de sources publiques fiables telles que le ministère américain de l'Énergie, l'OCDE, la Banque du Canada et les entreprises canadiennes de services publics. Un cas de sensibilité a été généré en mettant en correspondance les types de technologie du contrat externe avec ceux du modèle E3MC, révélant des différences dans les coûts marginaux d'investissement entre les deux approches (tableau 31).

Tableau 31. Différence en pourcentage du coût marginal d'investissement (par MW) dans le scénario de sensibilité par rapport au scénario central, par type de technologie pour certaines années (moyenne canadienne, basée sur les dollars constants de 2022)

Type de technologie	2025	2030	2035	2040	2045	2050
TCPG	-9 %	-9 %	-9 %	-9 %	-9 %	-9 %
CCPG	-5 %	-5 %	-5 %	-5 %	-5 %	-5 %
Petit OGCC*	-5 %	-5 %	-5 %	-5 %	-5 %	-5 %
GN CSC	-9 %	-14 %	-21 %	-25 %	-28 %	-31 %
Nucléaire	41 %	41 %	41 %	41 %	41 %	41 %
Hydro, charge de base	8 %	8 %	8 %	8 %	8 %	7 %
Hydro, de pointe	8 %	7 %	7 %	7 %	7 %	7 %
Petites centrales hydroélectriques	-25 %	-25 %	8 %	8 %	8 %	7 %
Biomasse	-1 %	-12 %	-21 %	-41 %	-41 %	-41 %
Biomasse CSC*	-3 %	-23 %	-27 %	-31 %	-31 %	-31 %
Éolien terrestre	1 %	2 %	0 %	1 %	1 %	2 %
Éolien en mer*	1 %	2 %	2 %	2 %	3 %	4 %
Solaire PV	-11 %	-10 %	-10 %	-10 %	-9 %	-6 %
Stockage	83 %	113 %	91 %	94 %	97 %	101 %

* Le contrat externe n'a pas déterminé les estimations des coûts marginaux d'investissement pour ces types de technologie. Pour estimer les valeurs du cas de sensibilité, les différences de pourcentage entre deux coûts pertinents du cas central ont été calculées et appliquées au scénario de sensibilité. Par exemple, la valeur pour le petit OGCC a été générée en multipliant l'OGCC du contrat externe par la différence de coût en pourcentage entre l'OGCC et le petit OGCC de l'E3MC. Le même traitement a été effectué pour le CSC de la biomasse (différence de pourcentage par rapport à la biomasse) et l'éolien en mer (différence de pourcentage par rapport à l'éolien terrestre).

Les coûts marginaux du capital issus du scénario de sensibilité ont été appliqués au même mix de réseaux électriques modélisé dans le cas central, générant les résultats suivants : par rapport au cas central sur la période d'analyse de 27 ans (2024 à 2050), les coûts marginaux du capital pour les nouvelles capacités du réseau électrique diminuent de 929 millions de dollars (1,7 %), les économies marginales sur les coûts de remise en état augmentent de 115 millions de dollars (208 %) et la valeur résiduelle du capital sur les mises hors service anticipées diminue de 98 millions de dollars (7,8 %).

Bien que le scénario de sensibilité génère des coûts d'investissement totaux similaires à ceux du scénario central (c.-à-d. 52,7 milliards de dollars contre 53,7 milliards de dollars), les changements

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apportés à la répartition des coûts d'investissement entre les provinces sont dignes de mention. Étant donné que les groupes au gaz naturel avec CSC et les groupes à la biomasse sont moins coûteux dans le scénario de sensibilité que dans le scénario central, les coûts différentiels totaux en Nouvelle-Écosse et en Alberta diminuent considérablement. De même, comme les groupes nucléaires et les centrales hydroélectriques de pointe sont plus coûteux dans le scénario de sensibilité par rapport au scénario central, les coûts différentiels totaux au Nouveau-Brunswick augmentent de manière significative. Les coûts pour les provinces dans le scénario de sensibilité sont présentés dans le tableau 32 ci-dessous.

Tableau 32. Coût d'investissement moyen annualisé (n=27) pour les nouvelles capacités de production d'électricité par type de technologie et par province dans le scénario de sensibilité (en millions de dollars)

	T.-N.-L.	N.-É.	N.-B.	Qué.	Ont.	Sask	Al.	C.-B.	Total
TCPG	0	37	-12	0	-2	-17	-42	0	-36
CCPG	0	0	-23	0	-4	-35	-85	0	-146
Petit OGCC*	0	-13	-25	0	-4	-39	-93	0	-175
GN CSC	0	0	0	0	0	127	643	0	770
Nucléaire	0	0	368	0	0	289	296	0	954
Hydro, charge de base	28	28	38	0	0	5	63	1	163
Hydro, de pointe	0	0	0	14	481	0	0	104	599
Petites centrales hydroélectriques	23	0	0	-3	103	7	-98	11	42
Biomasse	13	27	18	0	8	3	30	3	101
Biomasse CSC*	0	0	0	0	96	10	6	11	123
Éolien terrestre	19	73	0	2	-26	4	-28	5	49
Éolien en mer*	29	18	-0,04	0	0	0	0	0	47
Solaire PV	0	2	0	-0,01	4	8	4	0,1	18
Stockage	8	15	0	2	3	-2	9	3	39
Total	120	187	365	15	658	359	705	138	2,547
Différence en pourcentage par rapport au scénario central	12 %	-37 %	32 %	6 %	4 %	11 %	-14 %	11 %	-2 %

Lentille des petites entreprises

Le projet de règlement n'imposerait aucune exigence administrative ou de conformité aux petites entreprises telles que définies par le Secrétariat du Conseil du Trésor du Canada (moins de 100 employés ou revenus bruts annuels inférieurs à 5 millions de dollars).

Règle du « un pour un »

La règle du "un pour un" s'applique puisqu'il y a une augmentation progressive de la charge administrative pesant sur les entreprises. La proposition abrogerait deux titres réglementaires existants, entre 2035 et 2045, et introduirait un nouveau titre réglementaire, ce qui se traduirait par une diminution nette d'un titre réglementaire. (*Politique sur la limitation du fardeau réglementaire sur les entreprises*). Ces coûts sont décrits dans la sous-section « Coûts administratifs » de la section « Avantages et coûts ». Les coûts administratifs pertinents indiqués dans le tableau 22 (c'est-à-dire ceux qui seraient encourus de 2024 à 2033) ont été convertis en dollars constants de 2012, puis actualisés à l'année de base 2012 à l'aide d'un taux d'actualisation de 7 %. Selon cette méthodologie, le projet de règlement entraînerait une augmentation annualisée de la charge administrative de 9 963 $ ou 79,70 $ par installation. Il est

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important de noter que le calcul de la charge en vertu de la règle du un pour un ne comprend pas les coûts administratifs associés à la déclaration annuelle qui commencerait en 2035 et ne comprend que les coûts administratifs associés à la familiarisation avec la réglementation et à la soumission d'un rapport d'enregistrement et d'une assignation d'enregistrement. Le règlement sur la réduction des formalités administratives précise la méthodologie requise pour estimer les coûts de la charge administrative, qui se limite aux répercussions encourues au cours de la période de 10 ans qui commence lorsque le règlement serait enregistré. Ces coûts sont toutefois estimés et rapportés dans le cadre de l'ACA.

Coopération en matière de réglementation et d'harmonisation réglementaire

Le projet de règlement est un pilier essentiel du Plan de réduction des émissions, le plan climatique du Canada visant à atteindre une économie carboneutre d'ici 2050 (NZ2050). Il aurait une incidence non seulement sur le secteur de l'électricité, mais aussi sur d'autres secteurs à mesure qu'ils se décarbonisent à l'aide d'électricité propre. Le projet de règlement accélérerait les progrès vers un secteur de production d'électricité carboneutre, aidant le Canada à devenir une économie carboneutre d'ici 2050. Le Canada s'est joint à plus de 120 pays qui se sont engagés à atteindre la carboneutralité d'ici 2050, y compris tous les autres pays du G7. Le projet de règlement ne fera pas double emploi avec les règlements provinciaux ou territoriaux. Étant donné que l'électricité est en grande partie un produit national et qu'elle n'est exportée qu'aux États-Unis, le seul alignement international possible serait celui des États-Unis. Le 24 mars 2023, le président Biden et le premier ministre Trudeau ont publié une déclaration commune dans laquelle ils ont fait référence aux engagements pris par les deux pays pour parvenir à des réseaux électriques carboneutres d'ici 2035, les deux pays indiquant également leur intention de proposer avant cet automne des règlements qui réduiront les émissions de gaz à effet de serre du secteur nord-américain de l'électricité[36].

L'analyse de la modélisation visant à comprendre la dynamique potentielle du commerce de l'électricité entre les États-Unis et le Canada dans le cadre du REP aura lieu entre la prépublication dans la *Gazette du Canada*, partie I, et la publication finale dans la *Gazette du Canada*, partie II.

Évaluation environnementale stratégique

Conformément à la *Directive du Cabinet sur l'évaluation environnementale des projets de politiques, de plans et de programmes*, une évaluation environnementale stratégique (EES) a été réalisée pour le projet de règlement. L'EES a conclu que le projet de règlement devrait avoir des effets positifs sur l'environnement. Les effets environnementaux négatifs liés au projet de règlement pourraient inclure les répercussions localisées sur l'utilisation des terres associées aux nouveaux projets d'énergie solaire et éolienne, ou les considérations relatives au stockage/à l'élimination du combustible usé des centrales nucléaires, étant donné que le projet de règlement devrait favoriser un déploiement accru des sources de production d'électricité à faible teneur en carbone. Toutefois, par rapport aux effets environnementaux positifs de la réduction de la production d'électricité à partir de combustibles fossiles au Canada, les effets négatifs potentiels sur l'environnement seraient limités. Le projet de règlement soutient les objectifs de la Stratégie fédérale de développement durable (SFDD) 2022-2026, à savoir : « Accroître l'accès des Canadiens à une énergie propre », « Favoriser l'innovation et les infrastructures vertes au Canada », « Prendre des mesures relatives aux changements climatiques et leurs impacts », « Améliorer l'accès à des logements abordables, à de l'air pur, aux transports, aux parcs et aux espaces verts, ainsi qu'au patrimoine culturel au Canada ». Le projet de règlement devrait également contribuer aux objectifs de développement durable (ODD) connexes du Programme 2030 des Nations unies, en particulier l'ODD 3 Bonne santé et bien-être ; l'ODD 7 Énergie abordable et propre ; l'ODD 9 Industrie, innovation et infrastructure ; et l'ODD 13 Action pour le climat.

[36] Déclaration conjointe du premier ministre Trudeau et du président Biden | Premier ministre du Canada (pm.gc.ca)

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Sans le projet de règlement, dans le cadre du régime réglementaire actuel, le modèle E3MC estime que le secteur canadien de la production d'électricité rejetterait 44 Mt d'émissions en 2030, principalement en raison de la production d'électricité à partir de gaz naturel, qui devrait se poursuivre jusque dans les années 2040. Le projet de règlement est l'un des éléments du plan de réduction des émissions du Canada. Les progrès réalisés dans le cadre de ce plan seront examinés dans des rapports d'étape produits en 2023, 2025 et 2027. Des objectifs et des plans supplémentaires seront élaborés pour les années 2035 à 2050.

Analyse comparative entre les sexes plus

À l'aide d'une analyse comparative entre les sexes plus (ACS Plus), le ministère a déterminé que, par rapport à l'ensemble de la population canadienne, le projet de règlement peut avoir des effets disproportionnés, tant positifs que négatifs, sur certains groupes démographiques. En outre, les effets du changement climatique auront des répercussions disproportionnées sur ces mêmes données démographiques qui peuvent également être influencées par des considérations régionales, telles que des tempêtes plus violentes pour les communautés côtières ou des sécheresses et des incendies de forêt plus graves dans les régions plus enclavées et centrales. Ces effets peuvent être ressentis différemment par les personnes appartenant à ces groupes démographiques, et en particulier par les personnes dont les identités sociales se croisent et se chevauchent.

Le projet de règlement accélérerait les progrès vers un secteur de production d'électricité carboneutre, un élément clé pour que le Canada atteigne une économie carboneutre d'ici 2050. En vertu de sa portée en tant qu'instrument réglementaire fédéral, le projet de règlement peut aider à réduire les émissions de gaz à effet de serre du Canada et contribuer à l'action climatique mondiale. Étant donné que certains groupes démographiques de Canadiens sont plus vulnérables aux effets néfastes du changement climatique que l'ensemble de la population canadienne, le ministère s'attend à ce que ces groupes démographiques vulnérables ressentent davantage les effets positifs de l'atténuation réussie du changement climatique mondial[37,38]. Par conséquent, alors que le projet de règlement serait bénéfique pour ces groupes démographiques, ils incluraient des mesures visant à prendre en compte l'impact des coûts sur ces mêmes groupes.

Le projet de règlement a été conçu avec plusieurs flexibilités de conformité, y compris une flexibilité d'émission/durée basée sur la masse et une disposition de fin de vie réglementaire. Ces assouplissements en matière de conformité finissent par réduire les effets du projet de règlement sur les coûts, par exemple en diminuant la valeur résiduelle du capital en cas de mise hors service prématurée des actifs. Les provinces et les territoires sont responsables de l'approbation des modifications des tarifs d'électricité et les répercussions réelles du REP sur les tarifs dépendront des approches provinciales en matière de fixation des tarifs ainsi que de décisions d'investissement judicieuses et d'une bonne planification. Toutefois, les répercussions sur les tarifs ont plus de chance de se produire en Alberta, en Saskatchewan et en Nouvelle-Écosse et, dans une moindre mesure, au Nouveau-Brunswick, étant donné que leur plus grande dépendance à l'égard de la production de combustibles fossiles nécessiterait un renouvellement du capital plus important que dans les provinces qui disposent déjà d'une plus grande capacité non émettrice, telle que l'hydroélectricité. Le ministère a estimé les incidences sur les tarifs d'électricité par province (voir la section sur l'analyse des tarifs d'électricité), mais les incidences différentielles réelles du projet de règlement sur les tarifs d'électricité seraient influencées par les décisions provinciales sur la façon de respecter les normes réglementaires. De plus, le Ministère s'attend à ce qu'il y ait des impacts distributifs parmi certains groupes démographiques et communautés dans les provinces dépendantes des combustibles fossiles, en particulier pour ceux qui font face à l'intersectionnalité.

Même de faibles augmentations de tarifs pourraient avoir des répercussions disproportionnées sur les ménages à faible revenu, car ils consacrent une plus grande part de leur revenu à l'électricité et sont plus

[37] Intergovernmental Panel on Climate Change -IPCC Sixth Assessment Report: Summary for Policymakers.
[38] Personnes les plus affectées par les changements climatiques - Canada.ca

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susceptibles d'être confrontés à la pauvreté énergétique. Par exemple, un document d'orientation commandé par l'Institut canadien du climat a révélé que, dans toutes les provinces, les dépenses d'électricité représentaient une charge plus importante pour les ménages à faible revenu, soit entre deux et dix pour cent de leur revenu. En revanche, les ménages à revenus plus élevés dépensaient entre zéro et deux pour cent de leurs revenus pour l'électricité[39]. Les provinces de l'Atlantique peuvent être particulièrement touchées, car elles présentent généralement les taux les plus élevés de pauvreté énergétique au Canada[40]. En outre, les ménages à faible revenu peuvent ne pas avoir la capacité d'acheter des technologies qui leur permettraient de bénéficier de l'électrification des utilisations finales (par exemple, les thermopompes ou les véhicules électriques). Le ministère collabore avec des universitaires spécialisés dans l'économie des réseaux électriques afin de comprendre les effets potentiels du projet de règlement sur l'abordabilité de l'électricité (p. ex. les tarifs d'électricité), les coûts totaux de l'électricité supportés par les ménages (en tenant compte d'une électrification accrue) et les changements dans les dépenses d'électricité en tant que part du revenu. Cependant, ces impacts potentiels devraient être compensés par la diminution des dépenses des ménages en combustibles fossiles, en raison de l'électrification du chauffage domestique et des transports.[41]

Le ministère a l'intention de prendre en compte les résultats de ce travail dans son raisonnement lorsqu'il poursuivra l'engagement et l'élaboration du projet de règlement. Comme le montre le budget 2023, le gouvernement du Canada poursuit une série de mesures complémentaires qui soutiennent une transition abordable et fiable vers l'électricité propre et l'électrification. L'étude susmentionnée sur l'accessibilité financière de l'électricité pourrait contribuer à l'élaboration de futures mesures complémentaires potentielles.

Les enfants, les jeunes et les générations futures risquent d'être confrontés à des répercussions de plus en plus graves du changement climatique si celui-ci progresse au cours de leur vie et, par conséquent, ils devraient bénéficier davantage que les générations adultes d'aujourd'hui des réductions d'émissions à long terme. Le projet de règlement soutient les avantages intergénérationnels en accélérant la mise en place d'une infrastructure d'électricité propre, en créant les fondations des réseaux électriques propres de l'avenir, qui seront un élément clé pour fournir des avantages climatiques à long terme aux générations futures grâce au potentiel de réduction des émissions de l'électrification. Bien que le projet de règlement et la transition vers l'énergie propre entraînent des répercussions financières sur les générations actuelles, les générations futures bénéficieront en général de ces investissements. En outre, un accès accru à l'énergie propre peut avoir des avantages socio-économiques à long terme pour les générations futures en attirant l'industrie et les entreprises qui cherchent de plus en plus à utiliser de l'électricité propre et à réduire les émissions opérationnelles.

La composition actuelle du marché du travail du secteur de l'électricité au Canada est davantage représentée par certains groupes. Par exemple, en 2019, les hommes occupaient 67 % des emplois dans le secteur de la production[42], du transport et de la distribution d'électricité et représentaient 63 % de la main-d'œuvre dans le secteur des produits environnementaux et des technologies propres[43]. Les possibilités économiques offertes par la transition vers les énergies propres pourraient se traduire par une composition similaire du marché du travail. Toutefois, le Canada est plus susceptible de connaître une pénurie de travailleurs qualifiés que d'emplois durables dans le secteur de l'énergie propre[44] et il existe une opportunité d'inclure ceux qui sont actuellement sous-représentés dans l'industrie de la production, du transport et de la distribution d'électricité, tels que les femmes (33 %), les peuples autochtones (3 %)

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[39] Canadian Climate Institute - Volte face.
[40] Canadian Urban Sustainability Practitioners - Energy Poverty In Canada.
[41] Source: L'Institut Climatique du Canada - L'électricité et l'équité dans la transition énergétique du Canada.
[42] Centre canadien d'information sur l'énergie - Énergie et emploi.
[43] Statistique Canada - Caractéristiques relatives au genre de la population active du secteur des produits environnementaux et de technologies propres, 2012 à 2019 (statcan.gc.ca)
[44] Gouvernement du Canada – Plan pour des emplois durables.

et les minorités visibles (12 %)[45]. Les personnes handicapées[46] et les personnes LGBTQ2+[47] sont également probablement sous-représentées dans le secteur de l'électricité, mais il existe peu de données publiques ventilées permettant de quantifier leur représentation. Le Plan (provisoire) pour des emplois durables, lancé en février 2023, est un mécanisme qui permet d'atténuer ces répercussions. Une partie intégrante du Plan pour des emplois durables consiste à s'assurer que les circonstances particulières des groupes marginalisés et sous-représentés sont prises en compte afin de garantir leur participation pleine et égale à l'économie.

Le projet de règlement accélérant la transition vers l'électricité propre, le Canada assistera à une augmentation des formes de production d'électricité peu ou non émettrices (comme les énergies renouvelables) et à une réduction des formes de production d'électricité émettrices (comme la production d'électricité au gaz naturel sans dispositif de réduction des émissions). Au cours de cette transition, certains travailleurs qui travaillent dans le secteur de la production d'électricité à partir de combustibles fossiles devront peut-être changer d'emploi. Pour certains d'entre eux, cela peut nécessiter d'acquérir de nouvelles compétences, d'adapter leur parcours professionnel et leur trajectoire, ou de déménager vers des lieux où existent de nouveaux emplois dans le domaine de l'électricité propre. Cette transition touchera principalement les hommes, car le secteur de l'énergie basée sur les combustibles fossiles est dominé par les hommes[48]. Les travailleurs plus âgés peuvent également être confrontés à des défis particuliers lors de la transition vers un nouvel emploi, tels que des problèmes de santé, l'absence d'aménagements sur le lieu de travail et l'âgisme[49]. En 2019, 21 % des travailleurs du secteur de la production, du transport et de la distribution d'électricité étaient âgés de 55 ans et plus et 46 % étaient âgés de 45 ans et plus[50].

La production d'électricité à partir de combustibles fossiles continuera à jouer un rôle et nécessitera des travailleurs connaissant bien ces réseaux. En outre, ceux qui ont de l'expérience dans la production d'électricité à partir de combustibles fossiles peuvent posséder certaines compétences et connaissances transférables nécessaires pour travailler avec des formes de production d'électricité peu et non émettrices. Les étudiants, les jeunes travailleurs et les générations futures pourraient être mieux placés pour adapter leur parcours éducatif et leur carrière afin de tirer parti d'un secteur de l'énergie propre en pleine croissance. Même si certains travailleurs ne seront pas en mesure de faire la transition à partir d'emplois basés sur la production de combustibles fossiles, leur nombre devrait être faible, car le temps prévu entre la publication du projet de règlement et l'entrée en vigueur de la norme de rendement en 2035, ainsi que la mise à la retraite progressive de la production existante basée sur les combustibles fossiles, peuvent laisser le temps à la main-d'œuvre du secteur d'acquérir de nouvelles compétences et de profiter des opportunités d'emploi offertes par la transition vers l'énergie propre.

Les représentants autochtones ont souligné que l'abordabilité de l'énergie et l'accès continu à une énergie fiable sont des préoccupations pour les communautés autochtones et éloignées. Dans cette optique, les flexibilités de conformité du projet de règlement ont été conçues pour exempter efficacement la plupart des communautés autochtones et des communautés nordiques, rurales et éloignées qui ne sont pas connectées à un réseau électrique réglementé par la NERC, car elles n'ont souvent pas d'options abordables pour utiliser une production d'électricité non émettrice[51]. Dans le même temps, les représentants autochtones ont exprimé le souhait d'une plus grande inclusion des peuples autochtones dans la transition vers l'énergie propre afin de catalyser une transition vers l'abandon de la production

[45] Centre canadien d'information sur l'énergie - Énergie et emploi.
[46] Statistique Canada – Un profil de la démographie, de l'emploi et du revenu des Canadiens ayant une incapacité âgés de 15 ans et plus, 2017.
[47] Statistique Canada – Caractéristiques du travail et caractéristiques économiques des personnes lesbiennes, gaies et bisexuelles au Canada.
[48] Centre canadien d'information sur l'énergie - Énergie et emploi.
[49] Emploi et Développement social Canada- Promouvoir la participation des canadiens âgés au marché du travail - Canada.ca
[50] Centre canadien d'information sur l'énergie - Énergie et emploi.
[51] La Régie de l'énergie du Canada – Aperçu du marché : Projets d'énergie propre dans les communautés isolées autochtones et du Nord

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d'électricité à partir du diesel et de promouvoir les opportunités économiques locales. Alors que le nombre de communautés autochtones aidant à fournir des options d'électricité propre au Canada continue d'augmenter, le gouvernement reconnaît la contribution substantielle que les communautés autochtones peuvent jouer dans la réalisation d'un réseau d'électricité carboneutre. Le gouvernement reconnaît également le rôle important que la transition vers l'électricité propre peut jouer dans la réconciliation économique. Le gouvernement du Canada continuera à s'engager auprès des partenaires autochtones et des parties intéressées pour faire connaître les programmes d'énergie propre et les possibilités de financement pour les communautés qui ne sont pas connectées à un réseau électrique réglementé par la NERC (c'est-à-dire les « communautés hors réseau »). Ces efforts soutiendront les engagements plus larges du gouvernement en faveur de la réconciliation et de relations renouvelées avec les peuples autochtones afin d'atteindre les objectifs inscrits dans la Déclaration des Nations Unies sur les droits des peuples autochtones[52].

Raison d'être

Le projet de règlement contribuerait de manière significative à l'engagement du Canada d'atteindre la carboneutralité à l'échelle de l'économie d'ici 2050. L'atteinte de la carboneutralité à l'échelle de l'économie nécessitera une électrification à grande échelle des secteurs et des utilisations finales qui dépendent actuellement des combustibles fossiles, comme le transport, le chauffage des locaux et de l'eau et l'activité industrielle. Il est généralement admis que le niveau d'électrification nécessaire pour atteindre l'objectif de 2050 exigerait au moins un doublement de l'approvisionnement en électricité du Canada d'ici à 2050. Dans le scénario de référence, dans lequel le projet de règlement ne se produit pas, les provinces et les territoires vont faire des investissements importants dans la production et la transmission d'électricité au cours des prochains 25 ans pour répondre à cette demande croissante d'électricité. Dans ce contexte, le ministère estime que des investissements de plus de 400 milliards[53] de dollars sont nécessaires dans le cadre du remplacement de routine des installations vieillissantes et de l'expansion de la production pour répondre à l'augmentation de la demande découlant de la croissance démographique et économique, du passage aux véhicules électriques, de l'adoption du chauffage électrique pour les bâtiments et de l'électrification des processus industriels tels que la production d'acier et d'aluminium.

Si aucune mesure réglementaire n'est prise, le Canada devrait connaître une augmentation des émissions provenant du secteur de l'électricité[54]. L'action réglementaire a été considérée comme la meilleure approche pour envoyer des signaux sans équivoque en faveur d'une transition de l'économie des combustibles fossiles vers des sources non émettrices.

Les mesures réglementaires nécessiteront des investissements proportionnels. Alors que ces investissements devraient entraîner une augmentation des tarifs d'électricité, la recherche suggère qu'ils soutiendront un changement dans l'utilisation de l'énergie qui réduira en fait les dépenses globales des ménages en matière d'énergie. Le rapport Clean Electricity, Affordable Energy (juin 2023) du Climate Change Institute conclut que les dépenses énergétiques moyennes des ménages diminueront de 12 % d'ici à 2050, à mesure que les gens abandonneront les combustibles fossiles au profit de technologies plus efficaces telles que les véhicules électriques et les pompes à chaleur.

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[52] Gouvernement of Canada – Personnes les plus affectées par les changements climatiques.

[53] Développé par le modèle NextGrid, ce chiffre représente le coût cumulatif estimé de la production au cours de la période d'analyse de 27 ans et comprend les coûts d'exploitation de production existante et nouvelle ainsi que le coût en capital de la nouvelle production construite pour répondre à la demande croissante et pour remplacer la production existante qui finit par être mise hors service en raison de la fin de sa vie opérationnelle ou des dispositions du Règlement sur la réduction des émissions de dioxyde de carbone provenant de la production d'électricité au charbon et du Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité à partir de gaz naturel, déjà en vigueur. Le chiffre a été jugé conforme à l'estimation comparative faite par le modèle ministériel E3MC. Pour plus de clarté, le chiffre n'inclut pas les coûts estimés pour la conformité avec le projet de règlement, c'est-à-dire qu'il capture les coûts du scénario de référence.

[54] *Sources* : IEA, Trottier

Même si les dépenses énergétiques des ménages devraient diminuer, le gouvernement du Canada reconnaît également que l'électricité doit rester abordable. Alors que le coût supplémentaire pour s'assurer que l'augmentation de la production se fasse de manière à aboutir à un réseau carboneutre ne devrait ajouter qu'un faible pourcentage au coût global d'électricité, le gouvernement du Canada a engagé plus de 50 milliards de dollars pour aider à décarboniser le secteur. Ce financement pourrait couvrir plus de la moitié des coûts supplémentaires nécessaires pour garantir que cette transformation conduise à un réseau carboneutre, et il offre aux provinces la possibilité de réduire considérablement l'impact sur les tarifs, en particulier dans le Canada atlantique et les Prairies.

Avec l'ensemble des mesures fédérales complémentaires, le projet de règlement accélérerait l'évolution du Canada vers un secteur de l'électricité carboneutre. Bien que les provinces et les territoires soient responsables de la planification et de l'exploitation de leurs réseaux électriques, le gouvernement fédéral a compétence pour réglementer les émissions de GES en vertu de la LCPE. Par rapport au scénario de référence, le projet de règlement augmenterait les sources de production non émettrices et les sources émettrices avec dispositif de réduction des émissions et réduirait considérablement la production d'émissions sans dispositif de réduction des émissions d'ici 2035, et presque complètement d'ici 2050.

Alors que les systèmes existants et prévus de tarification du carbone mis en œuvre par les gouvernements provinciaux, territoriaux et fédéral pourraient réduire les émissions provenant de la production d'électricité à partir de combustibles fossiles, les résultats de la modélisation montrent que le projet de règlement est un moteur nécessaire qui garantirait que les émissions de GES du secteur n'augmentent pas indûment dans le cadre d'un scénario prévoyant une forte augmentation de la demande d'électricité.

L'approche du gouvernement du Canada en matière de lutte contre les changements climatiques est fondée sur le principe de la maximisation des améliorations de la performance environnementale tout en minimisant les répercussions économiques négatives. Le projet de règlement accorde au secteur de l'électricité des délais suffisants pour ajuster ses plans d'investissement afin de respecter les normes d'émissions de CO_2 proposées d'ici 2035. Une analyse coûts-avantages sociétale a été réalisée pour le projet de règlement, qui a indiqué qu'il entraînerait une réduction nette d'environ 342 Mt CO_2e d'émissions de GES entre 2024 et 2050 dans le cadre d'un scénario central dans lequel la demande d'électricité augmente de 40 %. L'avantage supplémentaire lié à la réalisation de ces réductions est estimé à 102,5 milliards de dollars, tandis que le coût supplémentaire est estimé à 73,6 milliards de dollars au cours de la même période. Il en résulte un bénéfice net pour la société d'environ 28,9 milliards de dollars[55].

Si les provinces et les services publics du Canada s'engageaient largement en faveur d'un réseau électrique carboneutre et profitaient pleinement du soutien financier du gouvernement fédéral, le programme d'électrification propre devrait être réalisé avec un coût supplémentaire minime pour les contribuables, tout en contribuant à réduire les coûts globaux de l'énergie pour les ménages et les entreprises.

Note : Les principaux aspects du projet de règlement sont présentés à l'annexe 1 du présent document, ainsi que la justification de ces aspects.

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Activités de mise en œuvre et d'application

Mise en œuvre

Une fois le projet de règlement publié dans la partie II de la *Gazette du Canada*, le personnel du ministère dirigera l'élaboration et la mise en œuvre des activités de promotion de la conformité, selon les

[55] En dollars constants de 2022, à un taux d'actualisation de 2 %.

besoins. Il peut s'agir de publier des informations sur le web, d'envoyer des courriels/lettres aux entités réglementées pour les informer de la publication, de répondre aux demandes d'information ou de clarification, d'envoyer des lettres de rappel (le cas échéant). Le projet de règlement entrera en vigueur à la date de sa publication dans la partie II de la *Gazette du Canada*, tandis que la norme de rendement entrera en vigueur à partir du 1er janvier 2035.

En général, les secteurs touchés par le projet de règlement connaîtront les exigences réglementaires proposées en raison des efforts considérables de mobilisation déployés par le ministère en 2022, notamment : de multiples webinaires (auxquels ont participé plus de 400 personnes, y compris des représentants d'associations industrielles et de secteurs industriels) et des documents diffusés par le ministère qui expliquent l'élaboration du projet de règlement, des réunions entre des fonctionnaires du ministère et des représentants de l'industrie et d'autres secteurs afin d'informer de l'évolution du projet de règlement, la demande par le ministère de commentaires écrits sur le cadre réglementaire proposé et l'analyse de ces commentaires par le personnel du ministère. Des activités d'engagement similaires sont prévues pour 2023.

Le ministère prévoit de publier *le Règlement sur l'électricité propre* dans la partie II de la *Gazette du Canada* en 2024. La date d'entrée en vigueur proposée serait le 1er janvier 2025. Les groupes dont la date de mise en service est antérieure au 1er janvier 2025 et qui répondent aux critères d'applicabilité devront s'enregistrer auprès du ministère de l'Environnement d'ici la fin de l'année 2025 et les groupes mis en service le 1er janvier 2025 ou après devront s'enregistrer dans les 60 jours suivant la mise en service. Après la publication, les groupes non au charbon mis en service avant le 1er janvier 2025 devront atteindre une norme de rendement de 30 t/GWh à partir du 1er janvier 2035 ou du 1er janvier de l'année suivant la fin de la durée de vie réglementaire du groupe (20 ans après la mise en service), la date la plus tardive étant retenue. Les groupes au charbon devront atteindre cette norme de rendement à partir du 1er janvier 2035, quelle que soit leur date de mise en service. Tous les groupes mis en service à partir du 1er janvier 2025, quel que soit le combustible utilisé, devront respecter la norme de rendement de 30 t/GWh à partir du 1er janvier 2035.

Activités de mise en œuvre

Étant donné que le projet de règlement est pris en vertu de la LCPE, les agents chargés de l'application de la loi appliqueront, lorsqu'ils vérifieront la conformité au règlement, la politique d'observation et d'application de la LCPE. Cette politique définit l'éventail des réponses possibles aux infractions présumées, y compris les avertissements, les directives, les ordres de conformité en matière de protection de l'environnement, les contraventions, les arrêtés ministériels, les injonctions, les poursuites pénales et les mesures de rechange en matière de protection de l'environnement (qui sont une alternative aux poursuites judiciaires après le dépôt d'une plainte pour une infraction à la LCPE). En outre, la politique explique quand le gouvernement du Canada aura recours à des poursuites civiles de la part de la Couronne pour le recouvrement des coûts.

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Annexe 1 Résumé du projet de règlement

Application Le projet de règlement s'applique aux groupes de production d'électricité qui répondent aux trois critères suivants :	**Raison d'être**
1. Utiliser n'importe quelle quantité de combustibles fossiles pour produire de l'électricité	La nécessité de lutter contre le changement climatique exige de limiter les émissions anthropiques de CO_2, et le projet de règlement devrait couvrir de la même manière toutes les sources potentielles d'émissions liées à la production d'électricité.
2. a une capacité égale ou supérieure à 25 MW	Évite les coûts associés aux groupes qui ne devraient pas être une source majeure d'émissions de GES au Canada, tout en offrant une certaine souplesse aux exploitants dans les endroits où l'infrastructure du réseau électrique n'est pas suffisante. En effet, les groupes de moins de 25 MW représentent actuellement environ 2 % des émissions du secteur de l'électricité au Canada. En outre, comme l'efficacité diminue avec la taille des MW, les groupes de moins de 25 MW sont trop inefficaces pour constituer une option viable en vue d'un déploiement à grande échelle de l'énergie de base.
3. sont connectés à un réseau électrique soumis aux normes de la NERC	Évite les coûts associés aux groupes qui : produisent principalement ou uniquement pour leur propre usage, car ces groupes sont le plus souvent intégrés à de grands complexes industriels qui seraient mieux réglementés par des instruments adaptés à leur secteur industriel ; et sont situés dans des régions éloignées ou nordiques, car ces groupes ne devraient pas être une source majeure d'émissions de GES au Canada et les régions nordiques n'ont pas beaucoup d'options pour obtenir de l'électricité fiable à faible taux d'émissions ou sans émissions, fournie à des prix compétitifs.
Inscription	**Raison d'être**
Le projet de règlement exigera que tous les groupes qui répondent aux critères d'applicabilité s'enregistrent d'ici la fin de l'année 2025 ou, pour les groupes mis en service après le 1er janvier 2025, dans les 60 jours suivant la mise en service.	Le projet de règlement exige que tous les groupes susceptibles de devoir se conformer à la norme de rendement s'enregistrent afin de démontrer qu'ils sont conscients de leurs obligations et de fournir au ministère les informations nécessaires pour mener des activités de promotion de la conformité et d'application avant que les normes de rendement ne s'appliquent.
Normes de rendement en matière d'émissions	**Raison d'être**

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On entend par groupe un ensemble composé de tout équipement physiquement connecté et fonctionnant ensemble pour produire de l'électricité, et qui (a) doit comprendre au moins une chaudière ou un moteur à combustion ; et (b) peut comprendre des brûleurs à conduit et d'autres dispositifs de combustion, des systèmes de récupération de la chaleur, des turbines à vapeur, des générateurs et des dispositifs de contrôle des émissions, y compris des systèmes de CSC capturant les émissions provenant de la production d'électricité.	Afin de maximiser les réductions d'émissions réalisables, le projet de règlement s'appliquerait à la production d'électricité au niveau le plus bas de la production, qui, dans le secteur de l'électricité, est défini comme « un groupe ». Cette approche est conforme à celle du *Règlement sur la réduction des émissions de dioxyde de carbone — secteur de l'électricité thermique au charbon* et du *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel.*
Les groupes, autres que ceux brûlant du charbon, mis en service avant le 1er janvier 2025 : La norme de rendement proposée (30 t/GWh) s'appliquera à partir du 1er janvier 2035 ou 20 ans après la mise en service du groupe.	Une approche progressive donnerait aux groupes existants le temps d'élaborer une stratégie de mise en conformité et de construire l'infrastructure nécessaire ou d'y avoir accès. En offrant cette flexibilité, la fiabilité du réseau électrique sera plus facilement maintenue aux niveaux actuels. Cette valeur correspond à l'intensité des émissions de la production de gaz naturel avec un taux de captage et de stockage du carbone (CSC) de 95 %, ce qui, selon les experts et les fournisseurs de CSC, devrait être possible d'ici à 2035..
Groupe mis en service à partir du 1er janvier 2025 : À partir du 1er janvier 2035, la norme de rendement proposée s'appliquera.	Le fait d'accorder aux nouveaux groupes un délai de 10 ans pour se conformer au projet de règlement offre une certaine souplesse. Les exploitants disposeront de suffisamment de temps pour entreprendre la construction et obtenir les matériaux nécessaires à la mise en place d'une capacité de production suffisante pour maintenir la fiabilité aux niveaux actuels.
Groupe qui brûle du charbon ou qui a augmenté sa capacité de production d'électricité d'au moins 10 pour cent depuis son enregistrement en vertu du projet de règlement : À partir du 1er janvier 2035, la norme de rendement proposée s'appliquera.	L'objectif principal de l'approche progressive est de faciliter la transition résultant de l'application de la norme de rendement. Les groupes visés par le *Règlement sur la réduction des émissions de dioxyde de carbone — secteur de l'électricité thermique au charbon* ont déjà bénéficié d'une telle approche progressive en vertu de ce règlement. Le fait de prévoir une deuxième période de transition fausserait les objectifs de réduction des émissions du projet de règlement.
Un groupe qui a cessé de brûler du charbon et qui a subi des « modifications majeures » : La norme de rendement proposée s'appliquerait à partir du 1er janvier 2035 ou du 1er janvier de l'année suivant la prolongation de sa durée de vie en vertu du *Règlement limitant les émissions de dioxyde de carbone provenant de la production*	Ces groupes considérablement modifiés sont inclus dans le *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel*. Les règlements sont harmonisés afin d'assurer la fiabilité du réseau électrique.

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d'électricité thermique au gaz naturel, selon la date la plus tardive. Pour plus d'informations sur la signification de « modification majeure », voir le paragraphe 3(4) du *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel.*	Les groupes ayant subi des modifications importantes n'ont aucune possibilité de fonctionner sans norme de rendement après 2039.
Seuls les groupes qui sont un solde exportateur de plus de zéro gigawattheure au cours d'une année civile donnée sont soumis à la norme de rendement pour cette année-là. Ceci s'applique aux groupes qui produisent de l'électricité destinée à un réseau électrique réglementé par la NERC et qui demandent de l'électricité à partir de ce réseau. Ainsi, la norme de rendement proposée ne s'appliquerait qu'aux groupes qui fournissent plus d'électricité à un réseau électrique réglementé par la NERC qu'ils n'en demandent.	Le projet de règlement impose des limites aux émissions de CO_2 associées à la production d'électricité. Le critère du solde exportateur de plus de zéro gigawattheure est inclus ici pour faire la distinction entre les installations qui sont connectées à un réseau électrique soumis aux normes de la NERC en tant que consommateur et celles qui sont connectées à un réseau électrique soumis aux normes de la NERC en tant que producteur. Le projet de règlement exige que le solde exportateur du groupe soit déterminé pour chaque année civile à partir de laquelle l'interdiction commencerait à s'appliquer à ce groupe. Un groupe ayant un solde exportateur de plus de zéro gigawattheure au cours d'une année civile devra se conformer à la norme de rendement au cours de cette année civile et au cours de toutes les années suivantes où il aura un solde exportateur de plus de zéro gigawattheure. Ces groupes seront également soumis aux règles de quantification à partir de la première année ou celui-ci à un solde exportateur de plus de zéro gigawattheure, lorsque l'interdiction commencera à s'appliquer à ce groupe.
Exceptions à l'obligation générale de respecter la norme de rendement de 30 t/GWh	**Raison d'être**
Flexibilité en matière de durée et d'émissions en fonction de la masse, limitant les groupes à faible utilisation et à faibles émissions à 450 heures par an et 150 kt par an. Cette exception peut être utilisée lorsque toutes les conditions applicables sont remplies au cours de l'année civile concernée. Si toutes les conditions liées à cette exception ne sont pas remplies au cours d'une année civile donnée, la norme de rendement de 30 t/GWh en moyenne annuelle doit être respectée cette année-là.	Permet aux groupes, qui sont encore capables de produire de l'électricité, de jouer un rôle de valeur ajoutée au réseau électrique en limitant les émissions. Pour les groupes qui ont besoin de cette flexibilité, les groupes utilisés pendant les périodes de forte demande ou lorsque les sources non émettrices ne sont pas disponibles. Ce faisant, la flexibilité réduit les coûts de mise en conformité et fournit des options pour l'alimentation de réserve, contribuant ainsi à éviter les problèmes de fiabilité et les pressions à la hausse sur l'accessibilité financière.
40 t/GWh disponibles jusqu'à la première des deux dates suivantes : sept ans après la mise en service d'un système de captage et de stockage du carbone (CSC) ou le 31 décembre 2039.	Permettre aux groupes qui ont déployé le CSC pour satisfaire à la norme de 30 t/GWh de disposer d'un temps limité pour ajuster le système de CSC et adapter son fonctionnement aux particularités du groupe. Permettre aux groupes qui pourraient ne pas être en mesure de respecter la norme de 30 t/GWh au

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Cette exception peut être utilisée lorsque toutes les conditions applicables sont remplies au cours de l'année civile concernée. Si toutes les conditions liées à cette exception ne sont pas remplies au cours d'une année civile donnée, la norme de rendement moyenne annuelle de 30 t/GWh doit être respectée au cours de cette année.	cours de leurs sept premières années d'exploitation de fonctionner à la norme moins stricte de 40 t/GWh aide les exploitants de réseaux à fournir une électricité fiable. En outre, il est prévu qu'une adaptation soit nécessaire pour la première génération de CSC appliquée aux groupes électrogènes au gaz naturel. Le besoin de cette exception diminuera au fil du temps et ne devrait plus être nécessaire d'ici à 2040. En conséquence, la limitation de cette flexibilité va dans le sens des objectifs de réduction des émissions de projet de règlement.
Circonstances d'urgence Le projet de règlement contient une disposition qui autorise la production d'électricité émettrice afin d'éviter une menace pour l'approvisionnement en électricité ou de le rétablir.	Elle permet une plus grande fiabilité du réseau électrique, ce qui améliore la qualité de vie et la sécurité des Canadiens. En outre, cette flexibilité réduit les coûts, car elle pourrait permettre à des groupes qui ne seraient autrement pas disponibles en cas d'urgence d'apporter une valeur ajoutée dans les situations d'urgence.
Quantification	**Raison d'être**
La mesure de la quantité d'électricité produite au cours d'une année, utilisée pour déterminer la conformité avec les normes de rendement en matière d'intensité des émissions, doit être effectuée sur une base brute.	Cette approche est conforme à celle adoptée dans le cadre du *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel* et tient compte des difficultés de quantification pour les groupes réglementés dont les activités sont intégrées à celles de tiers qui ne sont pas couverts par le règlement.
En ce qui concerne la quantité d'hydrogène qu'un groupe utilise pour produire de l'électricité, le projet de règlement exigerait que les émissions associées à la production de ce carburant soient incluses dans la détermination de l'intensité des émissions du groupe.	Bien qu'il n'y ait pas d'émissions de CO_2 provenant de la combustion de l'hydrogène, les émissions associées à sa production sont au moins égales aux émissions provenant de la combustion de combustibles fossiles dans un groupe de production d'électricité. Par conséquent, le projet de règlement exigerait que les émissions liées à la production d'hydrogène soient incluses dans la détermination de l'intensité des émissions du groupe.
En ce qui concerne la quantité de vapeur produite en dehors de l'installation d'un groupe et que celui-ci utilise pour produire de l'électricité, le projet de règlement exigerait que les émissions associées à cette production de vapeur soient incluses dans la détermination de l'intensité des émissions du groupe.	Les émissions associées à la production de vapeur sont au moins égales aux émissions provenant de la combustion directe de combustibles fossiles dans un groupe de production d'électricité. Par conséquent, le projet de règlement exigerait que les émissions liées à la production de vapeur soient incluses dans la détermination de l'intensité des émissions du groupe.
Rapports	**Raison d'être**
Le projet de règlement exigera que tous les groupes qui répondent aux critères d'applicabilité soumettent un rapport d'enregistrement comprenant des informations telles que : • l'identification de la personne responsable • L'emplacement et le nom du groupe ;	Cette mesure vise à fournir au ministère les informations nécessaires pour mener des activités de promotion de la conformité et de mise en œuvre avant l'application de la norme de rendement.

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• Schéma de procédé du groupe, y compris la date de mise en service de chaque chaudière ou moteur à combustion ; • la date de mise en service du groupe ; et • la capacité de production d'électricité du groupe.	
Le projet de règlement exigera que tous les groupes qui ont un solde exportateur de plus de zéro gigawattheure soumettent un rapport annuel comprenant des informations telles que l'intensité des émissions du groupe : • l'intensité des émissions ; • la production ; • les émissions ; et • les heures d'exploitation	Le but est de fournir au ministère les informations nécessaires pour garantir la conformité sur une base annuelle une fois que la norme de rendement s'applique à ce groupe.
Le projet de règlement exigera que les groupes qui déclarent ne pas avoir un solde exportateur de plus de zéro gigawattheure soumettent chaque année des informations concernant leur solde exportateur.	Étant donné que la norme de rendement se serait appliquée à ces groupes s'ils avaient un solde exportateur de plus de zéro gigawattheure, le ministère exige que ces groupes soumettent des documents justificatifs montrant qu'il n'y a pas un solde exportateur de plus de zéro gigawattheure. Tous les groupes doivent suivre leur solde exportateur, car la norme de rendement s'appliquera à partir de l'année applicable (à partir de 2035) pour ce groupe s'il y a solde exportateur de plus de zéro gigawattheure au cours de cette année.

Version Non Officielle

Proposed Clean Electricity Regulations

REGULATORY IMPACT ANALYSIS STATEMENT

(*This statement is not part of the Regulations.*)

Unofficial Version

Proposed Clean Electricity Regulations

REGULATORY IMPACT ANALYSIS STATEMENT

(*This statement is not part of the Regulations.*)

Executive summary

Issues: There is an urgent need to address climate change and Canada is committed to do its part. As climate change makes weather patterns more extreme and volatile, weather-related disasters (e.g., floods, storms and wildfires) are becoming more frequent and costlier. Insured losses as a result of catastrophic weather events in Canada totalled over $18 billion (2019 $CAD) between 2010 and 2019, while the number of catastrophic weather events in this period was over three times higher than it had been between 1980 and 1989.[1] Without rapid mitigation to reduce greenhouse gas (GHG) emissions to keep the global temperature increase below 1.5 °C (degrees Celsius) relative to pre-industrial levels, the adverse impacts of climate change are projected to escalate beyond adaptive capacity (the ability of social-ecological systems to adapt to environmental change)[2], affecting disproportionally, the most vulnerable of our population. In addition to catastrophic environmental and human health impacts, climate change will also entail significant social, cultural and economic losses in Canada. In an effort to help limit the worst of these impacts and based on the overwhelming conclusion of climate science, in 2021, Canada joined over 120 countries in committing to be a net-zero[3] GHG emissions economy by 2050.

In order to achieve net-zero GHG emissions economy-wide by 2050, the electrification of energy intensive activities, such as transportation, heating and cooling of buildings and various industrial processes, will be needed. For that electrification to have the desired impact, electricity generation will need to come from low and non-emitting electricity generation sources (see Table 3 for a description of these technologies) and this will need to happen much earlier than 2050. Considering, for example, that the Government of Canada (the Government) has proposed a sales mandate to ensure that 100% of light-duty vehicle sales would be zero GHG emissions vehicles by 2035[4], the Government has determined that without federal regulations to ensure the electricity-generating sector is prepared to supply cleaner electricity from low and non-emitting electricity generating sources by 2035, the sector would not be on a path that would enable the economy to reach net-zero GHG emissions by 2050.

Description: The proposed *Clean Electricity Regulations* (the proposed Regulations) would establish performance standards to reduce GHG emissions from fossil fuel generated electricity starting in 2035.

Rationale: The proposed Regulations would accelerate progress towards a net-zero electricity-generating sector, helping Canada become a net-zero GHG emissions economy by 2050. These efforts are needed to help limit the worst impacts of climate change. The proposed Regulations would set performance standards that would ensure that the sector achieves significant transformation by 2035, so that a robust foundation of clean electricity is available to power the electric technologies

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[1] *Source*: Tip-of-the-Iceberg-_-CoCC_-Institute_-Full.pdf (climatechoices.ca)
[2] *Source*: Adaptive capacity beyond the household: a systematic review of empirical social-ecological research - IOPscience
[3] Net-zero means cutting GHG emissions to as close to zero as possible, with any remaining emissions re-absorbed from the atmosphere, by oceans and forests for instance.
[4] *Source*: Canada Gazette, Part 1, Volume 156, Number 53: Proposed *Regulations Amending the Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations*.

(e.g., electric transportation) needed to support Canada's transition to a net-zero GHG emissions economy by 2050.

A cost-benefit analysis (CBA) was conducted using outputs from two Departmental models, NextGrid and E3MC, in a manner that seeks to minimize the system-wide (national) cost of meeting electricity demand subject to many constraints including policy parameters, system reliability and resource availability (e.g., geological constraints). The CBA acknowledges a variety of external economic and environmental changes that may occur over the analytical period by using conservative assumptions where appropriate and by testing alternative parameters in sensitivity analysis. The CBA represents central case modelling in which electricity demand increases by 40% over the analytical period. This central case scenario does not represent the only path that the electricity-generating sector could take to comply with the regulatory requirements, which will ultimately depend on investment decisions taken at the provincial level. Based on the set of assumptions used within the central case modelling, the CBA estimates that the proposed Regulations would result in a net reduction of 342 million metric tonnes (Mt) of carbon dioxide equivalent units (CO_2e) of GHG emissions between 2024 and 2050 (the 27-year analytical period). The incremental benefit associated with these GHG reductions, alongside cost-savings to the electricity system, is estimated to be $102.5 billion, while the incremental cost is estimated to be $73.6 billion over the 27-year analytical period, thereby resulting in a net benefit to society of $28.9 billion (2022 constant dollars, discounted to base year 2023 at a 2% discount rate).

Issues

There is an urgent global need to address climate change and Canada is committed to do its part. Climate change is responsible for significant extreme weather, food supply disruptions and increased wildfires worldwide. Over the past five decades in Canada, the annual costs of weather-related disasters like floods, storms and wildfires have risen from tens of millions of dollars to billions of dollars. From 2010 to 2019, the number of catastrophic events was over three times higher than during the 1980s. Weather-related disaster damages are among the most visible indicators of the costs of climate change; yet these costs provide an incomplete picture since they do not represent the full range of social (e.g., human health impacts), economic and environmental damages of climate change.[5] The world has already warmed by about 1.0°C (degrees Celsius) above pre-industrial levels (1850-1900) due to human activities and is experiencing the related negative impacts. At the current rate of warming of 0.2°C per decade, global warming will reach 1.5°C between 2030 and 2052.[6] Without rapid mitigation to reduce GHG emissions to limit global warming to 1.5°C, the adverse impacts of climate change are projected to escalate beyond adaptive capacity, affecting the most vulnerable members of our society disproportionally. In 2021, Canada joined over 120 countries in committing to a net-zero GHG emissions economy by 2050[7] to help limit global warming to 1.5°C and avoid the worst impacts of climate change.

In order to achieve net-zero GHG emissions economy-wide by 2050, the electrification of energy intensive activities, such as transportation[8], heating and cooling of buildings, as well as various industrial processes, will be needed. Even in the absence of regulatory action to control electricity sector emissions of carbon dioxide, this needed electrification will require significant investment to maintain, upgrade and expand Canada's fleets of electricity generators. Preliminary estimates by the Department indicate that such investments are likely to be more than $400 billion. If electrification is to have the required GHG reduction impact, then the investments will need to be directed to low and non-emitting electricity

[5] *Source*: *Tip of the Iceberg: Navigating the known and unknown costs of climate change*
[6] *Source*: Summary for Policy Makers_MF_3_online.indd (ipcc.ch)
[7] *Source*: Net-Zero Emissions by 2050 - Canada.ca

[8] The Emissions Reduction Plan included a commitment to introduce a regulated ZEV sales target that will require 100% of passenger car and light truck sales be zero-emission vehicles (ZEVs) by 2035, with interim targets of at least 20% by 2026 and at least 60% by 2030. The proposed regulations were published in the *Canada Gazette*, Part 1, on December 31, 2022.

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generation sources (see Table 3 for a description of these technologies) and this will need to happen much earlier than 2050. Without federal regulations to ensure the electricity-generating sector is prepared to supply cleaner electricity from low and non-emitting electricity generating sources by 2035, the sector would not be on a path that would enable the economy to reach net-zero GHG emissions by 2050.

Background

Urgent need to address climate change and Canada's climate change commitments

Reducing global GHG emissions to net-zero by 2050 provides the best chance to limit severe climate change related risks due to global warming. GHGs are a natural part of the Earth's geological systems however, human activities such as the burning of fossil fuels, are rapidly increasing levels of atmospheric GHGs. This increased concentration of GHGs in the atmosphere increases the temperature on Earth's surface (global warming) thus causing climate change. With increasing global surface temperatures, the probability of more droughts and increased intensity of storms will occur. As more water is evaporated into the atmosphere, it fuels increasingly powerful storms. More heat in the atmosphere and warmer ocean surface temperatures can lead to increased wind speeds in tropical storms. Rising sea levels expose higher locations not previously subject to the power and destructive capacity of oceans including the erosive forces of waves and currents. The Earth has already warmed by about 1.0°C above pre-industrial levels due to human activities and is experiencing the consequential impacts. In 2022, the Intergovernmental Panel on Climate Change (IPCC) released the report *Climate Change 2022: Impacts, Adaptation, and Vulnerability* that assessed that climate change, including increases in the frequency and intensity of climate and weather extremes, has caused widespread adverse impacts on ecosystems, agriculture, food, water, human health, livelihoods and economic activity. By disproportionately affecting the most vulnerable, especially through impacts on food, water and livelihoods, climate change can further exacerbate existing inequalities and inequities, both domestically and worldwide. The Canadian Disaster Database (CDD) tracks the most significant weather-related hazards, in terms of frequency, cost and displaced people. The CDD estimates that natural disaster costs totalled $35 billion (2019 $CAD) for 300 of the 645 weather-related disasters recorded since 1970. Floods were the most frequently reported weather-related disasters (40% of the total number of disasters), followed by severe thunderstorms (18%), wildfires (15%) and winter storms (9%). Hail, wind and ice events are included in these categories. The annual number of disasters in the CDD has steadily increased since the 1970s, fluctuating between a low of eight in the early 1970s to a high of 27 per year in 2016. In addition to an increase in the number of disasters, the cost per disaster has also increased—rising from an average of $8.3 million (2019 $CAD) per event in the 1970s to an average $112 million (2019 $CAD) per event in the 2010s. This change represents a 1,250% increase over four and a half decades.[9]

At the current rate of warming of 0.2°C per decade, global warming will reach 1.5°C between 2030 and 2052. Considering the impacts of climate change associated with global warming already reaching 1.0°C above pre-industrial levels, near-term increases in global warming reaching 1.5°C would cause unavoidable increases in multiple hazards and present risks to ecosystems and humans beyond adaptive capacity. Near-term actions that would limit global warming close to 1.5°C would substantially reduce future risks compared to those at higher warming levels. The effects of widespread climate change are already evident in many parts of Canada and are projected to intensify in the future. In addition to significant environmental loss, including accelerated habitat and species loss, this will have a negative impact on the social (e.g., human health impacts), cultural and economic life of Canada and its people.

[9] *Source*: Tip-of-the-Iceberg-_-CoCC_-Institute_-Full.pdf (climatechoices.ca)

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According to the International Energy Agency[10], global annual GHG emissions have increased 60% from 21.4 Gigatonnes (Gt)[11] in 1990 to 34.2 Gt in 2020. Over the same period, Canada's emissions[12] increased 13% from 595 Megatonnes (Mt) to 672 Mt. Although Canada's contribution to global totals may seem relatively small, per capita Canada ranks as the 7th highest GHG emitter globally.[13]

Canada has been active in seeking to reduce GHG emissions both internationally and nationally

Internationally

- In 2015, Canada and 194 other countries concluded negotiations on the Paris Agreement; In the Agreement Canada set a goal to reduce its GHG emissions by 30% below 2005 levels by 2030, which Canada amended in 2021 to set a 2030 goal of reducing GHG emissions by 40-45% below 2005 levels.

- In 2021, Canada joined over 120 countries by committing to be a net-zero GHG emissions economy by 2050.

- On May 11, 2023 the United States Environmental Protection Agency published the Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants.

Nationally

- In 2016, the Pan-Canadian Framework on Clean Growth and Climate Change (PCF): Canada's plan to address climate change and grow the economy was published and included more than 50 measures to drive down Canada's GHG emissions, help build resilience across the country and support climate innovation for clean economic growth. The PCF was developed in collaboration with Canada's provinces and territories and in consultation with national Indigenous organizations, interested parties and Canadians.

- The federal *Greenhouse Gas Pollution Pricing Act* (GGPPA) came into force on June 21, 2018. The GGPPA establishes the framework for the federal backstop carbon pollution pricing system (putting a price on GHGs) which consists of two parts: a regulatory charge on fossil fuels like gasoline and natural gas, the fuel charge under Part 1 of the GGPPA and regulatory trading system for industry known as the Output-Based Pricing System (OBPS), under Part 2 of the GGPPA.. The OBPS is designed to put a price on carbon pollution, creating an incentive for industrial facilities from sectors at significant risk of carbon leakage and competitiveness impacts to reduce their GHG emissions per unit of output. Under the Government of Canada's approach to pricing carbon pollution, provinces and territories have the flexibility to implement a carbon pricing system that makes sense for their circumstances, provided that the system meets the minimum national stringency criteria (the federal benchmark). Since 2019, every jurisdiction in Canada has had a price on carbon pollution.

- In 2020, the Healthy Environment and a Healthy Economy: Canada's strengthened climate plan to create jobs and support people, communities and the planet was published. It builds on the

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10 Source: https://www.iea.org/reports/global-energy-review-co2-emissions-in-2021-2

11 1 Gigatonne is equal to 1,000,000,000 tonnes. 1 Megatonne is equal to 1,000,000 tonnes. 1 Kilotonne is equal to 1,000 tonnes. 1 tonne is equal to 1,000 kilograms.

12 *Source: National Inventory Report 1990 – 2020*.

13 CO_2 emissions (metric tons per capita) - Canada | Data (worldbank.org), to see the global ranking including Canada, download the data and sort the 2019 column from highest to lowest.

PCF and included 64 strengthened and new federal policies, programs and investments to cut carbon pollution and build a stronger, cleaner and more resilient and inclusive economy.

- In 2021, the Canadian Net-Zero Emissions Accountability Act (CNZEAA) was enacted. The CNZEAA formalizes Canada's target to achieve net-zero GHG emissions economy-wide by 2050. It establishes a series of interim GHG emissions reduction targets at 5-year milestones and requires a series of plans and reports to help Canada achieve its milestones on the way toward that goal. Pursuant to the CNZEAA, the Net-Zero Advisory Body (NZAB) was established with the mandate to provide independent advice with respect to achieving Canada's target of net-zero GHG emissions economy-wide by 2050.[14]

- In March 2022, Canada's 2030 Emissions Reduction Plan (2030 ERP): Canada's next steps for clean air and a strong economy was published. The 2030 ERP includes key measures the Government of Canada intends to take in order to achieve the 2030 target (40-45% GHG emission reductions below 2005 levels), an interim GHG emissions objective for 2026, an overview of relevant sectoral strategies and a projected timetable for implementation of these measures. The 2030 ERP provides a roadmap towards achieving net-zero GHG emissions economy-wide by 2050.

Canada's climate change strategy for electricity generation

According to Canada's 2022 National Inventory Report (2022 NIR)[15], Part 3, in 2020, Canada generated 575,000 Gigawatt hours (GWh)[16] of electricity and emitted 62 Mt of carbon dioxide (CO_2) equivalent, abbreviated as CO_2e[17], (9.2% of total national GHG emissions). Of the electricity generated that year, 16% came from emitting electricity sources that use fossil fuels (e.g., coal, natural gas, other fuels such as refined petroleum products) while 84% were from low and non-emitting electricity sources that use renewable fuels (e.g., nuclear and renewables, such as hydro, wind and solar) to power generation. Table 1 provides a breakdown of electricity generation by emitting and low and non-emitting electricity sources and CO_2e emissions by region in 2020.

Table 1. Electricity generation (GWh) by emitting and low- and non-emitting electricity sources and CO_2e emissions (kt) by region in 2020.

Region	Electricity generation (GWh)	% of generation from low- and non- emitting electricity sources	% of generation from emitting sources	CO_2e emissions (kt) from emitting electricity generation
NL	39,800	97%	3%	950
PE	660	100%	0%	0.3
NS	9,420	21%	79%	6,340
NB	12,000	70%	30%	3,470
QC	188,000	99%	1%	290

[14] Since then, the NZAB have provided advice through many publications, such as Net-Zero Pathways Initial Observations and Advice for Canada's 2030 Emissions Reduction Plan.
[15] *Source*: 2022 NIR Website, download 'can-2022-nir-14apr22.zip" file to see the 2022 NIR, Part 1, 2 and 3.
[16] Gigawatt hours, abbreviated as GWh, is a unit of energy representing one billion (1 000 000 000) watt hours and is equivalent to one million kilowatt hours. Gigawatt hours are often used as a measure of the output of large electricity power stations.
17 A carbon dioxide equivalent or CO_2 equivalent, abbreviated as CO_2e, is a metric measure used to compare the emissions from various greenhouse gases on the basis of their global-warming potential (GWP), by converting amounts of other gases to the equivalent amount of carbon dioxide with the same global warming potential.

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ON	149,000	94%	6%	3,710
MB	37,200	100%	0%	28
SK	24,000	22%	78%	13,900
AB	55,800	15%	85%	32,700
BC	58,400	97%	3%	420
YK	530	83%	17%	54
NT	350	74%	26%	62
NU	200	0%	100%	150
Canada	575,000	84%	16%	62,100

The 2022 NIR shows that GHG emissions from the emitting electricity-generating sector have been cut by more than half from 132 Mt of CO_2e in the year 2000 to 62 Mt of CO_2e in 2020, while electricity generation, which was 539,000 GWh in 2000, did not fluctuate significantly. Table 2 provides a breakdown by emitting and low- and non-emitting electricity generation sources in 2000 and 2020 in Canada.

Table 2. Electricity generation (GWh) by emitting (coal, natural gas, other fuels) and low- and non-emitting (nuclear, hydro, other renewables) electricity generation sources by fuel type for Canada in 2000 and 2020.

Electricity generation (GWh) by fuel	Coal	Natural gas	Other fuels	Nuclear	Hydro	Other renewables	Total electricity generation (GWh)	CO2e emissions (kt) from emitting electricity generation
2000	106,440	26,616	13,250	68,650	323,130	260	538,346	132,044
% of total electricity generation	20%	5%	2%	13%	60%	0.05%	100%	-
2020	35,940	47,978	7,346	92,590	354,980	36,180	575,013	62,197
% of total electricity generation	6%	8%	1%	16%	62%	6%	100%	-

Table 2 shows that the GHG emission reductions from 2000 to 2020 were mostly driven by a significant decrease in the use of coal as a fuel to generate electricity (from 20% in 2000 to 6% in 2020) and adoption of low and non-emitting electricity generation sources (from 73% in 2000 to 84% in 2020).

Federal actions (regulatory and non-regulatory) to support the reduction of GHG emissions from the emitting electricity-generating sector

Canada continues to be active in seeking GHG emission reductions from the electricity-generating sector, this includes federal regulatory and non-regulatory actions including:

Regulatory actions

- The *Canadian Environmental Protection Act, 1999* (CEPA, or the Act) aims to prevent pollution and protect the environment and human health. The Act sets out rules for preventing and regulating toxic substances, including GHG substances (e.g., carbon dioxide and methane) and provides the authority for the Governor in Council (GIC) to make regulations to manage pollution in Canada. Regulatory authorities under both CEPA and the GGPPA have been used to reduce GHG emissions from the electricity sector.

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- In 2012, the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* were published for the purpose of establishing a regulatory regime to reduce CO_2 emissions resulting from conventional coal-fired electricity generation.

- In 2018, the *Regulations Amending the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* were published to accelerate the reduction of CO2 emissions from conventional coal-fired electricity generation by 2030 to help Canada meets its GHG emissions reduction commitment under the Paris Agreement.

- In 2018, the Government published the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity* to limit CO_2 emissions from the use of natural gas as a fuel to generate electricity in Canada.

- Since 2019, the federal backstop carbon pollution pricing system has been in place in jurisdictions that requested it, or that did not have a system that meets the federal national minimum stringency criteria (the federal benchmark). Carbon Pricing is applied to industrial sectors, including the electricity sector through the federal output-based pricing system (OBPS) or an applicable provincial carbon pricing system[18]. These systems, including the OBPS, are designed to ensure there is a price incentive for companies to reduce their GHG emissions and spur innovation while maintaining competitiveness and protecting against carbon leakage. Under the OBPS, industrial facilities face a carbon price on the portion of their GHG emissions that are above their facility emission limit, which is determined based on relevant output-based standards (OBS). As of 2030, electricity generation capacity from gaseous fuel that meets specified criteria and that was put in place on or after January 1, 2021, whether at an existing or new facility, would be fully exposed to the carbon price. Any such electricity generation capacity that existed prior to 2021 would be subject to the carbon price only for the portion of GHG emissions above the OBS of 370 t /GWh.

Non-regulatory actions

- Since 2016, the Government of Canada has directed over $50 billion in targeted investments towards building net-zero electricity systems in Canada. This includes programs such as the Smart Renewables Electrification Pathways Program (SREP), a $1.57 billion program, including $600 million announced in Budget 2022, which provides support for smart renewable energy and electrical grid modernization projects, including projects that support capacity building. Since December 2021 to February 2023, the SREP provided funding for about $164.5 million[19]. In Budget 2023, the Government of Canada announced an increase in funding of $3 billion for the SREP.

- The Government of Canada provides low-interest financing to clean electricity projects through a variety of mechanisms, including investments and financing from the Canada Infrastructure Bank (CIB) and Strategic Innovation Fund, as well as federal tax incentives. These initiatives total more than $20 billion. This includes:

    - The Canada Growth Fund ($15 billion to fund investments in support of a net-zero GHG emissions economy); and

[18] Most Canadian jurisdictions have their own carbon pricing systems for industry. In 2022, the federal OBPS applies in Manitoba, Prince Edward Island, Yukon, Nunavut and partially in Saskatchewan.
[19] *Source*: Projects funded to date - Smart Renewables and Electrification Pathways Program (canada.ca)

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- Budget 2023 announced a new investment target for the Canada Infrastructure Bank of at least $10 billion through the Clean Power priority area for building of major clean electricity.

Despite these actions and the fact that in 2020, only 16% of the electricity generated in Canada came from emitting electricity sources, analysis shows that Canada's emitting electricity-generating sector is not on a path to achieve significant emissions transformation by 2035. For Canada to meet its economy-wide, net-zero emissions target by 2050, significant growth in clean electricity supply is needed. There is a broad consensus among researchers that the increased use of electric technologies (e.g., electric transportation, heating and cooling of buildings and solutions for various industrial processes) could, in the absence of a clean electricity standard, result in a significant increase in GHG emissions from fossil fuel electricity generation (see sensitivity analysis section).

Current and emerging electricity system technologies needed to meet net-zero GHG emissions

A wide range of technologies are available in Canada to form the electricity system, as described in Table 3.

Table 3. Electricity system technologies and summary of specifications in 2022 (Canada average, 2022 constant dollars)*

Technology	Description	Capital cost ($/kW)	Fixed O&M cost ($/kW)	Variable O&M cost ($/MWh)	Average fuel cost ($/MWh)	Estimated operating lifetime (years)
OGCT	Oil/gas combustion turbine (akin to Brayton cycle)	1,625	20	6	61	45
OGCC	Oil/gas combustion turbine equipped with waste heat recovery system and steam turbine (akin to Brayton cycle plus Rankine cycle)	1,571	26	4	61	45
Small OGCC	Similar to OGCC but with lower generating capacity	1,737	33	4	61	45
NG CCS**	Natural gas combustion turbine (typically OGCC though OGCT is possible), equipped with carbon capture and sequestration technology	3,310	51	11	61	45
OG Steam	Steam turbine (akin to Rankine cycle) generation from oil/gas combustion	5,239	135	9	56	45
Coal	Steam turbine generation from coal combustion	3,825	47	3	13	45
Coal CCS**	Steam turbine generation from coal combustion, equipped with carbon capture and sequestration technology	8,111	95	11	13	45
Biomass	Thermal generation utilizing biomass as fuel	5,634	138	10	3	45
Biomass CCS**	Thermal generation utilizing biomass as fuel, equipped with carbon capture and sequestration technology	10,485	192	18	3	45
Waste	Thermal generation utilizing waste material as fuel	2,085	27	8	13	45
Nuclear	Steam turbine generation utilizing nuclear fission as heat source	9,120	167	4	-	60
Base Hydro	Hydroelectric projects with little or no storage (akin to run-of-river)	7,071	137	-	-	100

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Peak Hydro	Hydroelectric projects with associated reservoirs, able to generate power during peak demand periods	7,200	49	2	-	100
Pumped Hydro	Hydroelectric projects that are able to store energy for later use	7,200	49	2	-	100
Small Hydro	Similar to base hydro but with lower generating capacity	4,362	49	2	-	100
Onshore Wind	Onshore wind turbines	2,117	51	-	-	30
Offshore Wind	Offshore wind turbines	6,370	148	-	-	30
Solar PV	Photovoltaic solar panels	1,825	18	-	-	30
Geothermal	Thermal generation that utilizes geothermal energy to produce steam	11,712	224	7	-	30
Wave	Process that utilizes wave motion to generate power	8,905	439	-	-	20
Storage	Varying technologies capable of consuming energy in one time period then releasing energy in another time period, with an associated efficiency loss	1,409	11	1	-	15
Other	Other technologies not covered above	5,462	172	7	32	45

* All cost estimates in this table were derived by the Departmental model E3MC. For more information on this model, see the Benefits and Costs section.
** CCS represents carbon capture and storage of emissions.

Generally speaking, the electricity system technologies in Table 3 can be categorized into unabated emitting generation, abated emitting generation, non-emitting generation and storage. Certain unabated emitting generation technologies are able to reach lower-emitting profiles by burning “clean fuels” such as renewable natural gas or hydrogen. Abated emitting generation technologies reach lower-emitting profiles by deploying abatement technology such as carbon capture and storage (CCS), which can be purpose-built, or installed in some facilities as a retrofit.

There are also emerging electricity system technologies that may become more widely available in Canada as those technologies continue to develop. For example, fuel cells may offer longer-term energy storage than batteries (months or years versus days or weeks) but are currently underutilized since fuel cell technology is not yet sufficiently efficient relative to batteries. Certain advanced variable renewable generation technologies such as offshore wind and geothermal are set to become more available in the medium term (though subject to geological constraints), as are small modular reactors (SMR) which are designed to be more widely deployable than conventional nuclear due to their compact size. Abated emitting generation, non-emitting generation and storage are all expected to contribute significantly to Canada’s future net-zero electricity system, though some degree of technological development will be required to make that happen.

Objective

The objectives of the proposed Regulations are to:

1. Help Canada achieve its climate change commitments towards achieving net-zero GHG emissions economy-wide by 2050 by constraining emissions from unabated thermal power generation. This transition will support global efforts to address climate change and help limit associated damage; and
2. Reduce GHG (i.e., CO_2) emissions from emitting electricity generation beginning in 2035.

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Description

The proposed Regulations would achieve emission reductions through the application to electricity generating units of an annual basis emission performance standard of 30 tonnes of CO_2 per GWh of electricity produced ("30 t/GWh"), with limited exceptions.

The proposed Regulations apply to all electricity generation units that meet the applicability criteria. A unit means an assembly of equipment that operates together to generate electricity and must include at least a boiler or combustion engine and may include CCS systems.

Further information on the rationale of the regulatory design can be found in Annex 1.

Application

The proposed Regulations would apply to any unit that meets the three following criteria:

1. Uses any amount of fossil fuels to generate electricity;
2. Has a capacity of 25 MW or greater; and
3. Is connected to an electricity system that is subject to North American Electric Reliability Corporation (NERC) standards ("NERC-regulated electricity system").

Registration

The proposed Regulations would require all units that meet the applicability criteria to register with the Minister of the Environment by the end of 2025 or, for units commissioned after January 1, 2025, within 60 days of commissioning.

Emission performance standards

The 30 t/GWh annual average performance standard would apply starting on:

1. January 1, 2035, for units that combust coal or petroleum coke;
2. January 1, 2035, for any unit commissioned on or after January 1, 2025;
3. January 1, 2035, for a unit that has increased its electricity generation capacity by 10% or more since registration of the unit;
4. on the latter of January 1, 2035 or January 1 of the calendar year in which the prohibition set out in subsection 4(2) of the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*[20] begins to apply to a "significantly modified" unit, which is one that has ceased burning coal ; or
5. For any other unit, the latter of January 1, 2035, or 20 years after its commissioning date.

Only units that are net exporters in a given calendar year are subject to the performance standard in that year. Net exporters generate electricity that is supplied to and in some cases, demand electricity from an electricity system regulated by NERC standards. Therefore, the performance standard would only apply to those units that supply more electricity to a NERC-regulated electricity system than they demand from it.

[20] For further information on the meaning of "significantly modified", refer to subsection 3(4) of the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*.

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Exceptions from meeting the 30 t/GWh annual average performance standard

In a given calendar year, a unit could comply with the proposed Regulations using one of the following exceptions to the 30 t/GWh annual average performance standard where all of the conditions related to the exceptions are met:

1. A unit, other than one combusting coal, that operates up to 450 hours per year (“450 hr/yr”) may emit no more than 150 kilotonnes of CO2 per year ("150 kt/yr”), where for clarity, 450 hr/yr is equivalent to operating 24 hours/day for 18.75 days/year; or

2. A unit using CCS may emit no more than an annual average of 40 t/GWh if it can demonstrate that the unit is capable of operating at 30 t/GWh (i.e., documentation showing that the unit operated at or below 30 t/GWh for two periods of at least 12 consecutive hours, with at least 4 months between those two periods in a given calendar year). This exception is only available until the earlier of seven years after commissioning of a carbon capture and storage (CCS) system or December 31, 2039.

If all of the conditions related to the exceptions are not met in a given calendar year, then the 30 t/GWh annual average performance standard must be complied with in that year.

Furthermore, the proposed Regulations would allow any unit subject to them to operate during any period of emergency circumstance without being required to meet the performance standard during such a period if the unit has been provided an exemption to do so by the Minister of the Environment. In general, an emergency circumstance is one that arises due to an extraordinary, unforeseen, and irresistible event.

Quantification

The proposed Regulations would set out the manner for determining compliance with the performance standard in a calendar year. In general, for each unit, an operator would need to determine the unit’s emissions intensity, which is the unit’s total emissions divided by its total generation. The quantification requirements apply to each unit annually, as of the calendar year that the prohibition first applies to the unit, regardless of whether the unit is subject to the prohibition in a calendar year,

The unit’s total generation is the quantity of electricity it generated during the course of a year measured on a gross basis.

The unit’s total emissions, which can be determined using either a fuel-based method or continuous emissions monitoring systems (CEMS), includes as applicable:

- The quantity of emissions produced by the combustion of fossil fuels for electricity generation; and
- The quantity of emissions associated with the production of any hydrogen fuel or steam that is used by the unit to produce electricity, regardless of the location or supplier.

For clarity, in cases when hydrogen is used as a fuel in the electricity generating unit, the combustion of that hydrogen does not directly produce any CO_2 emissions from the unit; therefore, any CO_2 emissions associated with the hydrogen’s production must also be quantified and included in the unit’s total emissions.

As included in the proposed Regulations, the unit’s total emissions can exclude the quantity of emissions captured by its CCS system only if these emissions are permanently stored in a storage project that meets prescribed criteria.

Final Version

Reporting

The proposed Regulations would require all units that meet the applicability criteria to submit a registration report that includes information such as: identification of the responsible person, the location and name of the unit, a process diagram of the unit, including the commissioning date of each boiler or combustion engine, the commissioning date of the unit and the unit's electricity generating capacity.

On an annual basis, the proposed Regulations would require all units that have net exports to an electricity system subject to NERC standards to submit a report that includes information such as the unit's: annual average emission intensity and if applicable, in the case of units with a CCS system installed in the last seven years, documentation demonstrating that the unit operated at or below 30 t/GWh for two periods of at least 12 continuous hours in the reporting year, gross generation, emissions and hours of operation.

A declaration of no net exports may be provided for a unit that does not expect to have any net exports from the time the performance standard would begin to apply to that unit, which would reduce its reporting requirements. If these units never have net exports to the electricity system, they will remain exempt from both the prohibition and the quantification requirements in the proposed Regulations.

All units would be required to track their net exports as the performance standard would apply from the applicable year (as of 2035) for that unit if there are net exports in that year. These units would also be subject to quantification rules from the applicable year.

The *Regulations Designating Regulatory Provisions for the Purposes of Enforcement (Canadian Environmental Protection Act)* would be amended to include the proposed Regulations and make the contravention of applicable rules punishable by appropriate penalties, such as increased fines and jail time.

Regulatory development

Consultation

The Department of the Environment (the Department) started consultations with interested parties to the proposed Regulations in March 2022. Interested parties include utility companies, provincial and territorial governments, Indigenous groups, industry associations, environmental non-governmental organizations (ENGOs), unions and labour organizations, researchers and academics in the field of climate change or energy and the general public.

Starting with the Clean Electricity Standard Discussion Paper, which laid out the Department's initial proposal on how to achieve a transition to net-zero electricity and introduced the key components that any such policy should incorporate, namely emission reductions, electricity affordability and electricity system reliability. In its proposal, the Department noted that implementing the proposed Regulations would require careful balancing of these three criteria, as maximizing outcomes for any one criterion could place achieving either of the other two at risk. For example, maximizing affordability could endanger emission reductions as the cheapest option to keep the electricity system operating in many places is to continue using existing natural gas-fired generation. In the same way, maximizing reliability may hinder emission reductions as reliability in the status quo requires having sufficient natural gas generation available. An electricity system that is neither affordable, nor reliable could discourage the transition to clean electricity generation needed to achieve the economy-wide net-zero target in 2050.

Interested parties' engagement

- On March 15, 2022, interested parties were invited to submit comments on the Clean Electricity Standard Discussion Paper which laid out the proposed regulatory approach towards supporting net-zero GHG emissions in the electricity sector by 2035.

- On March 23-24, 2022, interested parties were invited to attend an 'Opening the Loop' informational webinar on the Discussion Paper. Over 160 submissions were received, following which, a webinar was held on July 21-22, 2022, with a focus on these comments.
- A second round of engagement and consultation began on July 26, 2022, with the publication of the Proposed Regulatory Frame for the Clean Electricity Regulations ("the regulatory frame") which provided more specifics on the proposed regulatory design. Over 120 submissions were received on the regulatory frame.
- A third webinar was held on September 13-14, 2022, with a focus on modelling assumptions. A number of bilateral modelling sessions were held with various provinces to ensure that the assumptions used in federal modelling were correct.
- On October 3, 2022, an Indigenous information session was hosted, with attendees from First Nations, or their representatives.

As of December 2022, nearly 100 bilateral meetings were held with interested parties to further discuss and provide feedback on the approach of the proposed Regulations.

Following these consultations, more than 330 submissions on the proposal were received. Interested parties commented on:

- the role of natural gas and liquid-fired electricity generation post-2035 to ensure reliability of electricity systems;
- the treatment of emitting forms of industrial electricity generation;
- the potential for adverse impacts on electricity rates; and
- the readiness of emerging non-emitting technology to supply reliable electricity by 2035, specifically the availability of generation and storage technologies.

Interested parties have also voiced general support for de-carbonization[21] of the electricity system and a willingness to engage in the development of the proposed Regulations to ensure that the regulations would achieve the necessary emissions reductions while maintaining affordability and reliability.

In general, feedback on the proposed Regulatory Frame for the Clean Electricity Regulations (July 26, 2022) was positive, in that many interested parties viewed the proposed regulatory frame as a workable approach to achieving net-zero. However, interested parties raised specific concerns, discussed below, that the Department has considered in depth while developing the proposed Regulations.

Interested Parties' concerns

Natural gas and liquid fuel fired electricity generation post-2035:

Many utility companies voiced concern that electricity system operators would not be able to maintain reliability without at least some operation post-2035 from the types of generators that are currently powered by natural gas, or liquid fuel because they are flexible and highly controllable. Many voiced support for an exemption that would allow system operators to use these generators to maintain reliability, as long as it is on a time and emissions-constrained basis.

ENGOs, non-emitting power producers and sustainable industry representatives voiced that the role for natural gas and liquid fuel to power electricity generation should be minimal after 2035 and that a requirement that would limit the use of natural gas would reduce emissions to as close to zero as possible.

[21] Reduction or elimination of carbon dioxide emissions from a process such as manufacturing or the production of energy.

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To address interested parties' concerns, the Department has built emissions constrained flexibilities for natural gas and liquid fuel generation into the proposed Regulations to:

- Phase in the performance standard on existing units by applying the standard to any given unit 20 years following its commissioning date, known as a unit's End of Prescribed Life[22] (EoPL);
- Allow covered units to operate in the event of emergency situations without having to meet the performance standards;
- Allow covered units to operate during peaking periods under a total emissions threshold (rather than emissions intensity) and total time limit in a given year without having to meet the intensity-based performance standard; and
- Set the performance standard at a level (i.e., 30 t/GWh) that could be met by natural gas units with CCS so that these units can supply flexible and highly controllable generation to electricity systems.
    - Furthermore, the proposed Regulations would allow covered units that are using CCS as part of a compliance strategy to meet an annual average emission intensity of 40 t/GWh for the first 7 years following the capture system's commissioning, or until December 31, 2039, whichever comes first.

A few utility companies cautioned against allowing too much flexibility for natural gas generation, as this could discourage the rollout of non-emitting generation and energy storage. Furthermore, ENGOs voiced concern that any role for non-emergency gas-fired electricity generation should be greatly limited after 2035. These parties cautioned against underestimating the ability of technologies such as energy storage, hydrogen, CCS, nuclear and other non and low-emitting emerging technologies to ensure electricity system reliability by 2035.

The time limitations incorporated into the above four compliance flexibilities could limit the use of unabated natural gas and liquid fuels for electricity generation in the post-2035 period. It is expected that this would lead to increasing use of non and low-emitting generation sources.

Higher emitting provinces, utilities, system operators and power producers requested flexibility in the application of the performance standard. Specifically, they shared their concern that, without flexibility, there would be insufficient natural gas capacity to backup variable renewables (e.g., wind and solar) and that units now under construction may not be commissioned in time (by 2025) to benefit from the existing unit EoPL described above.

To address this concern, the proposed Regulations include flexibilities that would:

- Allow covered units to operate in the event of emergency circumstances; and
- Allow covered units to operate if meeting both a total emissions threshold and total time limit in a given year (e.g., mass-based exception to 30 t/GWh performance standard).

ENGOs and industry operating in the clean technology space were seeking clear signals that the proposed Regulations would require electricity system operators to dispatch non-emitting sources in advance of emitting ones. In consideration of these comments, the Department noted that the reliability of electricity systems are of critical importance for provinces and territories, as they are responsible for designing and operating electricity systems. The proposed Regulations set a stringent performance

[22] "Prescribed Life" means 1. in the case of a significantly modified boiler unit referred to in the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*, a period that begins on the commissioning date of the unit and ends on the date the prohibition set out in those Regulations begins to apply to the unit; or 2. for all other units, the period that begins on the commissioning date and ends on the later of:
(i) December 31 of the calendar year that is 20 years after the commissioning date; and
(ii) December 31, 2034.

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standard, but maintain technology neutrality, allowing provinces and territories, or electricity system operators to choose what types of generation to procure.

Many ENGOs asked for the inclusion of interim standards (i.e., applying a standard before 2035) to avoid a build-out of new natural gas generation before the performance standard applies in 2035. Interim standards are not proposed for the following reasons[23]:

- As new natural gas units represent a substantial investment that can only be recouped after 10 or more years of operation, the Department expects that by setting a standard of 30 t/GWh starting in 2035, new units built before 2035 would nonetheless be designed to meet the 30 t/GWh standard so that they could continue to operate past 2035;
- Most of the natural gas units that will come online before 2025 were planned before the proposed Regulations were announced. Few units could be conceived, designed and built before January 1, 2025, the date at which units are counted as "new" under the proposed Regulations and therefore cannot benefit from the 20-year EoPL; and
- As an alternative to complying with the 30 t/GWh performance standard, units can instead operate at any emissions intensity for a maximum of 450 hours per year, with a limit of 150 kilotonnes of emissions per year, to provide back-up or peaking capacity. It could be possible to commission a new unabated unit after 2025 that could operate under these provisions. This has benefits for geographical regions in Canada that do not have access to the deep geological storage needed for installing CCS technologies. However, it is expected that it would be less financially favourable to only operate a new unit for such a limited amount per year, which would limit the commissioning of new unabated units for this purpose. Furthermore, the total emissions of these units would be less than if they were to operate under the 30 t/GWh emissions standard.

Treatment of industrial emitting electricity generation:

Many ENGOs and some utilities shared their concern that there could be a large build-out of industrial electricity generation "behind-the-fence"[24] in order to avoid the proposed Regulations, since electricity units that are not connected to a NERC-regulated electricity system would not be covered under the proposal.

Upon review, the Department noted that:

- The proposed Regulations are designed to target emissions from the electricity sector. Industrial emissions are subject to other policies, such as carbon pricing.
- The proposed Regulations would cover all generation units that are connected to a NERC-regulated electricity system, regardless of whether or not the units are physically located 'behind-the-fence', i.e., units located at an industrial site.
- In any given compliance year, industrial units that have net exports to a NERC-regulated electricity system (i.e., they sell more electricity than they buy) would have to meet the proposed Regulation's performance standard in that year. This will create a co-benefit because even electricity produced by units with net exports but used to meet onsite electricity demand would have to meet the 30 t/GWh performance standard. This means that only electricity produced by units that do not have net exports to the electricity system would not have to meet the performance standard.
- Emissions from electricity generation facilities are covered by the *Output-Based Pricing System Regulations* (OBPSR) or the applicable provincial or territorial carbon pricing system. This means that emissions from units that do not have net exports to a NERC-regulated electricity system in a given year will still be exposed to a price signal to reduce emissions.

[23] There are other flexibilities in the proposed Regulation that can allow a unit to operate without needing to meet the 30 t/GWh performance standard, however these flexibilities are not relevant to the discussion of interim standard.

[24] "Behind-the-fence" means a unit whose electricity generation capacity is suited for the industrial facility at which it is located, thus resulting in the majority of its electricity being consumed, most of the time, by the industrial facility.

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- Currently, there are not sufficient, cost-effective low, or non-emitting alternatives for wholly 'behind-the-fence' generation. In this context, covering 'behind-the-fence' fossil-fired generation units under the proposed Regulations when these units are not net exporters of electricity to a NERC-regulated electricity system would result in negative impacts to industry that would not otherwise occur under the other policies described above (e.g., carbon pricing). Furthermore, 'behind-the-fence' units would need to be addressed as Canada moves towards a net-zero economy in 2050.
- In some cases, the fuels that are used in 'behind-the-fence' generation would otherwise be required to be flared[25] if they were not used for electricity production. As such, if the proposed Regulations were to cover 'behind-the-fence' units, it is likely that many of the units would opt to avoid regulatory coverage by ceasing to produce electricity from these fuels and instead flare them. In such scenarios, emissions would increase from the flaring activity without any realized benefit (i.e., electricity generation) from the fuels' combustion.

For the above reasons, the proposed Regulations would not apply to 'behind-the-fence' units that do not have net-exports to the grid.

Potential adverse impacts on electricity prices:

Some provinces and utilities voiced concerns about the costs of complying with the proposed Regulations and the potential impacts on rate affordability for households, businesses and industry. They noted that fossil-fuel reliant electricity systems would bear higher costs in the net-zero transition than will electricity systems that have substantial non-emitting resources, e.g., wind. These interested parties requested funding programs, tax-measures and other incentives to minimize the short-term costs of the transition. In particular, provincial governments of New Brunswick and Nova Scotia raised that these provinces experience higher rates of energy poverty[26] in the country and noted concern that the proposed Regulations could exacerbate this problem.

The Department notes that:

- specific engagement was held regarding the analysis of the expected effect on the price of residential electricity;
- separate from the proposed Regulations and its objectives, the Government of Canada has announced, developed and implemented complementary measures, including funding, to help support the net-zero transition, thereby indirectly reducing the proposed Regulations' impact on electricity prices;
- the proposed Regulations would include flexibilities that help utilities manage the cost impact of their electricity system while maintaining reliability; and
- the Department engaged with a number of academics with expertise in the economics of the electricity system to understand the potential impacts of the proposed Regulations on electricity affordability, which informed the establishment of the regulatory standards and flexibilities within the proposed Regulations. This engagement will continue as the Department considers comments received during the pre-publication period.

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[25] Flaring is the controlled burning of fuel or waste gas that takes place during some forms of production and processing. Fuel or waste gas is ignited at the top of a flare stack, causing the characteristic flame associated with flaring. Some odours may be associated with flaring. - Natural Gas Flaring & Venting | Canadian Association of Petroleum Producers (capp.ca)

[26] Energy poverty is households' inability to afford energy services; it may manifest as a heat-or-eat dilemma, self-imposed brownouts for financial reasons, or keeping home temperature at lower-than-comfortable room temperature, *Source*: Canadian Climate Institute - Electricity affordability and equity in Canada's energy transition.

Readiness of emerging non-emitting technology to supply reliable electricity by 2035

A few utilities, ENGOs, companies operating in the clean technology space and some academics cautioned against allowing too much flexibility for natural gas generation, as this could discourage the rollout of non-emitting generation and energy storage. These parties cautioned against underestimating the ability of technologies such as energy storage, hydrogen-ready gas turbines, CCS, nuclear and other non and low-emitting emerging technologies to ensure electricity system reliability by 2035.

Several provinces and territories noted that CCS is not a decarbonization option for them because their geology does not allow for carbon storage.

Several provinces and territories expressed concern over the readiness of key decarbonization technologies such as CCS, SMR and energy storage, noting that their costs will be very high even when ready for wide scale deployment. Experts in CCS technology noted that while the 30 t/GWh performance standard is achievable by these systems, there may be periods in the early years of deploying these systems when some adjustments to the systems may be needed in order for them to achieve the performance standard consistently.

The Department notes that:

- new investments in the development and deployment of emerging technologies such as CCS, energy storage and SMR are anticipated;
- compliance flexibilities such as prescribed life for units commissioned before January 1, 2025, or the mass-based emission/duration exception allow for continued operation of natural gas and liquid-fired generation in these periods; and
- the proposed Regulations contain an exception that allows a covered unit having CCS technology to operate at an average emission intensity of 40 t/GWh if the unit can prove that it is capable of operating at or below 30 t/GWh (i.e., documentation showing that the unit operated at 30 t/GWh for two periods of at least 12 consecutive hours, with at least 4 months between those two periods in a given compliance year) and that:
    - The unit can only use the exception for up to 7 years following the commissioning date of that CCS system or until December 31, 2039, whichever comes first;
    - During this 7-year period, a unit whose CCS system cannot achieve 30 t/GWh on an annual average basis can continue to operate while the person responsible for the unit undertakes the actions required to improve the unit's emission performance to meet the 30 t/GWh standard on an annual average basis. These actions could involve multiple rounds of emissions testing, assessing the CCS system for its performance fault, designing the solution to allow for 30 t/GWh operation, building/implementing this solution and commissioning it. Based on the timelines associated with major retrofits of electricity generating units, it is expected that 7 years would provide ample time to take the actions required to improve the CCS system's performance. By 2040, it is expected that CCS systems will have improved to the point that this flexibility would no longer be needed; and
    - The CCS exception ensures that the CCS systems are designed to meet an ambitious carbon capture rate, while allowing some minor flexibility in case operational circumstances made it difficult to initially achieve this rate consistently.

Modern treaty obligations and Indigenous engagement and consultation

As required by the *Cabinet Directive on the Federal Approach to Modern Treaty Implementation*, an assessment of modern treaty implications was conducted for the proposed Regulations. The assessment examined the geographic scope and subject matter of the proposed Regulations in relation to modern treaties in effect. The assessment did not identify any modern treaty implications or obligations.

The Department has taken a distinctions-based engagement approach with Indigenous Peoples:

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- inviting representatives of National Indigenous Organizations (NIOs) to informational webinars;
- meeting bilaterally with NIOs and extending an open offer to continue meeting on a bilateral basis; and
- hosting a specific webinar for First Nations to hold a conversation about the proposed Regulations.

Indigenous interested parties have identified energy affordability as a concern that is becoming more acute and recommended that the design of the proposed Regulations protect electricity affordability. Some also expressed that there is strong Indigenous awareness about the impact of health risks from burning fossil fuels and an interest in understanding the benefits of reduced air pollutants that the proposed Regulations could create.

The Department notes that:

- separate from the proposed Regulations and its objectives, the Government of Canada has announced, developed and implemented complementary measures to help support the transition, including funding, that is either targeted for Indigenous led projects or is available to Indigenous led projects, thereby indirectly reducing the proposed Regulations' impact on rates;
- the proposed Regulations would include flexibilities that help utilities manage the cost impact of their electricity system while maintaining reliability;
- the Department has engaged with Indigenous-led organizations with insight into energy affordability in Indigenous communities in order to understand the potential impacts of the Regulation on electricity affordability. This engagement will continue during development of the Regulations; and
- The potential health benefits of the proposed Regulations are discussed further in this regulatory impact analysis statement.

The Department also heard about intersections between the proposed Regulations and broader concerns surrounding economic reconciliation and the participation of Indigenous Peoples in the clean energy transition, particularly through economic participation.

In addition to the above considerations, the Department has reviewed all questions and comments received from Indigenous interested parties and will continue to consider them in the development of the proposed Regulations. Some issues being raised, including Indigenous communities' views on the energy transition and economic participation, are of interest not just in the context of the proposed Regulations, but also for the broader clean electricity transition.

Instrument choice

The *Cabinet Directive on Regulations* (CDR) requires departments and agencies to assess the full suite of instruments available (both regulatory and non-regulatory) under federal acts and regulations to select the most effective and appropriate instrument or mix of instruments to address a policy issue. Considering the urgency to address climate change and Canada's climate change goals towards becoming a net-zero GHG emissions economy by 2050, a transformational change will be required in every sector of the Canadian economy including the electricity-generating sector.

Transforming electricity systems must occur much earlier than 2050, since it requires growth of electricity supply to support the use of more electric technologies, such as electric transportation, heating and cooling of buildings, solutions for various industrial processes and that the electricity generated results in net-zero GHG emissions. If this transformation is not under way by 2035 there is a risk that Canada may not meet its climate change goals of becoming a net-zero GHG emissions economy by 2050.

In determining the most effective and appropriate instrument or mix of instruments that would ensure the electricity-generating sector is on a path to achieve the required transformation by 2035, the Department considered the current federal regulatory regime affecting the sector in the baseline scenario (status quo),

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including non-regulatory actions. It was determined that the current federal regulatory regime does not ensure that the sector would achieve the required transformation by 2035 and therefore federal regulations would be required. A summary of this assessment is given below:

Baseline scenario / no new controls

The baseline scenario approach involves maintaining existing restrictions on emissions of coal-fired electricity as set out in the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*, which generally set a performance standard of 420 t/GWh. In addition, the baseline scenario approach involves maintaining existing restrictions on emissions of natural gas electricity generation set out in the *Regulations Amending the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*. These latter Regulations set an emission intensity standard of 420 t/GWh for natural gas boilers or combustion engine units that are 150 MW and greater and an emission intensity standard of 550 t/GWh for combustion engine units that are under 150MW.

As of 2030, electricity generation capacity from gaseous fuel that meets specified criteria and that was put in place on, or after January 1, 2021, whether at an existing or new facility, would be fully exposed to the carbon price. Any such electricity generation capacity that existed prior to 2021 would be subject to the carbon price only for the portion of GHG emissions above the OBS of 370 t /GWh. In the baseline scenario, unabated natural gas generation and associated GHG emissions would be expected to rise in future years as more electric technologies are implemented (e.g., electric transportation) in Canada. This would limit the ability for Canada to achieve net-zero GHG emissions economy-wide by 2050. Most electricity generating facilities are subject to carbon pollution pricing under the federal Output Based Pricing System Regulations (OBPSR), or under provincial or territorial systems that meet the federal benchmark (i.e., the minimum national stringency criterial that all carbon pricing systems in Canada must meet). Under the OBPSR, electricity generation facilities that are covered under the federal system must provide compensation for GHG emissions that are above their facility emissions limit. Compensation can be provided by paying the excess emissions charge ($65/tonne of CO_2e in 2023, rising to $170/tonne in 2030), or by providing one compliance unit (surplus credit, offset credit or recognized provincial offset credit) for each tonne of emissions above their limit. If emissions are below their limit, facilities receive surplus credits for the quantity between the actual emissions and the emissions limit, which can be sold or banked to meet future compliance obligations.

Under the OBPSR, emissions limits are calculated by multiplying a facility's production by the relevant output-based standard (OBS) associated with the activity, which can be considered a free allocation. Electricity generation is subject to different OBSs based on fuel type. For solid fuel, the OBS started at 800 t/GWh in 2019 and will decrease to 370 t/GWh in 2030. For liquid fuel, the OBS is 500 t/GWh and for gaseous fuel, the OBS is 370 t/GWh. In addition, gas-fired electricity generation facilities that start generating electricity on or after January 1, 2021 and that meet certain size and other designed requirements have an OBS of 370 t/GWh in 2021 decreasing to 0 t/GWh in 2030. This means that in 2030, new gaseous electricity facilities would have no free allocation and would therefore pay for 100% of the GHG emissions emitted from the facility. Modelling by the Department indicates that electricity sector emissions would not decrease sufficiently so as to meet the objectives of the proposed Regulations and could in fact, increase significantly in the coming decades.

The Government of Canada has core infrastructure investment programs that focus on clean energy system infrastructure with total combined investments of nearly $10 billion. This includes programs such as the Smart Renewables Electrification Pathways Program (SREP), a $1.57 billion program, including $600 million announced in Budget 2022 that provides support for smart renewable energy and electrical grid modernization projects, including projects that support capacity building. Since December 2021 to

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February 2023, the SREP provided funding for about $164.5 million[27]. In Budget 2023, the Government of Canada announced an increase in funding of $3 billion for the SREP.

The Government of Canada provides low-interest financing to clean electricity projects through a variety of mechanisms, including investments and financing from the Canada Infrastructure Bank (CIB) and Strategic Innovation Fund, as well as federal tax incentives. These initiatives total more than $20 billion. This includes the Canada Growth Fund ($15 billion to fund investments in support of a net-zero GHG emissions economy) and funding for the clean power sector announced in Budget 2023 through the Canada Infrastructure Bank ($10 billion through the clean power priority area for building of major clean electricity).

The Government of Canada expects that these investment programs will be of critical importance, as they would work in tandem with the proposed Regulations to help achieve Canada's goals of transforming the electricity system by 2035 to help achieve a net-zero emissions economy by 2050.

Using carbon pricing to reduce electricity sector emissions

Currently, the minimum national stringency criteria for carbon pricing systems (the federal benchmark) require that explicit carbon price-based systems, such as the federal Output-Based Pricing System, be designed such that the marginal price signal is equal to the benchmark price but allows systems to apply lower average carbon costs to industrial facilities to mitigate carbon leakage and competitiveness risks that can arise due to carbon pricing. Systems do this by requiring facilities to pay the carbon price for emissions above an emissions limit and issuing tradeable credits for facilities that emit below that limit. This approach creates a price signal at the benchmark price on every tonne of emissions but because facilities don't have to pay the carbon price on all of their emissions, it reduces average carbon costs and risk of carbon leakage and adverse competitiveness impacts.

Reducing GHG emissions from the electricity sector could be achieved by ensuring that a high carbon price is paid for every tonne of electricity emissions. If electricity generators had to pay the carbon price for every tonne of emissions, their average carbon costs would increase. The Department has conducted various modelling exercises and determined that a carbon price of $170/tonne applied to every tonne of electricity sector emissions does not move the sector far enough towards net-zero by 2035. Furthermore, in a high-demand modelling scenario, a carbon price of $170/tonne was not found to be sufficiently high so as to make near-zero emission electricity generation technologies significantly more competitive than emitting technologies; if non-emitting and near-zero emission generation technologies are not the most cost competitive options, it is expected that sector emissions would increase. Therefore, while requiring the carbon price to be paid on every tonne of emissions from electricity generation would be expected to achieve additional emission reductions, it would not achieve reductions to the extent needed to achieve the required emission reductions towards net-zero by 2035.

Moreover, the carbon pollution pricing systems in Canada are an economy-wide tool that provides a strong price incentive to reduce emissions in the most cost-effective manner across all emission sources it covers. It provides this strong incentive by its design, which does not set specific limits for emissions from individual sectors. They do not guarantee a certain level of reductions from a specific sector and as such, are not the right tool to ensure achievement of the objective of a net-zero electricity sector.

In the absence of a regulated standard, it is likely to be more economic for utilities to i) continue to use unabated natural gas to generate reliable baseload power and pay an increased price on pollution, or ii) to acquire and remit surplus or offset credits. In the absence of other constraints, this would be the choice generators would likely make rather than transition their generating equipment to produce reliable, near-zero emission electricity through technological solutions like wind or solar coupled with energy storage or natural gas coupled with modern CCS technology. Overall, analysis by the Department indicates that

[27] *Source*: Projects funded to date - Smart Renewables and Electrification Pathways Program (canada.ca)

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requiring electricity generators to pay a high carbon price on all of their emissions would not be sufficient on its own, to guarantee that the electricity sector would achieve by 2035, the transformation required to support Canada's climate change goal of becoming a net-zero GHG emissions economy by 2050.

The proposed regulatory approach

Reducing GHG emissions to transition towards a net-zero electricity system and to support a net-zero emissions economy by 2050 would require a planned and permanent transition away from unabated electricity generation. The proposed Regulations would build on the existing regulatory framework for the electricity sector to continue progress towards the permanent transition away from unabated fossil-fired electricity generation to low or non-emitting sources of generation. Significant progress in this direction could be accomplished through the application of stringent performance standards within the 2035 timeframe. The proposed performance standard would require fossil fuel-fired generation to be abated in order to provide baseload generation. This approach would also provide a clear regulatory reference point that lays out what would constitute clean electricity, while providing power producers with timelines adequate to adjust their capital investment plans. However, given that the proposed performance standard would be set at a non-zero value and that the proposed regulatory approach would include several compliance flexibilities, the electricity generation sector would continue to have low levels of residual emissions. Additional actions would be needed before the electricity generation sector could fully achieve net-zero emissions.

Within the proposed regulatory approach, the Department considered several options for key parameters including the emissions performance standard, compliance flexibilities, capacity threshold, industrial generation coverage and an End of Prescribed Life. The impacts of varying these parameters are assessed in the sensitivity analysis section of the RIAS.

Regulatory analysis

Benefits and costs

Data sources and analytical parameters

A cost-benefit analysis (CBA) is undertaken to determine the incremental impacts (costs and benefits) accrued under a regulatory scenario relative to those accrued under a baseline scenario. For this proposal, the CBA compares the difference in impacts between a scenario with the proposed Regulations and a scenario without them. The main driver of incremental impacts for the proposed Regulations is the electricity system mix modelled in the baseline scenario versus that modelled in the regulatory scenario. In the CBA, electricity system mix refers to the set of infrastructure that makes up the electricity system (e.g., non-emitting generation assets, abated emitting generation assets, emitting generation assets, storage assets and transmission lines that connect between electric utility systems), the technical specifications of that infrastructure (e.g., capacity, generation, fuel usage, emissions intensity, operation and maintenance factors) and the usage of that infrastructure (e.g., electricity system only generation, industrial generation, back-up or emergency generation). Under the proposed Regulations, Canada's electricity system mix would shift towards low or non-emitting sources of electricity generation more quickly and to a greater extent than it would under the baseline scenario and there would be greater investment in storage and transmission capacity.

The electricity system mix and related factors that could be realized under a baseline scenario versus under a regulatory scenario were projected by two Departmental models. The first model is NextGrid, which is a capacity expansion model that identifies optimal investment and operation decisions across Canada's electricity system, minimizing the system-wide (national) cost of meeting demand subject to many constraints including policy parameters, system reliability and resource availability (e.g., geological constraints). The second model is the Energy, Emissions and Economy Model for Canada (E3MC), which

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itself contains two components. The first component of E3MC is Energy 2020 (E2020), which is an integrated, multi-region, multi-sector North American model that simulates the supply, price and demand for all fuels. E2020 estimates energy output and prices for each sector in regulated and unregulated markets and simulates how energy prices and government measures may affect the choices that consumers and businesses make when they buy and use energy. E2020's outputs include changes in energy use, energy prices, greenhouse gas emissions, air pollutant emissions, investment costs and possible cost savings from measures, which are used to identify the direct effects stemming from measures aimed at reducing GHG emissions. The resulting savings and investments from E2020 are then used as inputs into the second component of E3MC, The Informetrica Model (TIM). TIM is used to examine consumption, investment, production and trade decisions in the whole economy. It captures the interactions among industries, as well as the implications for changes in producer prices, relative final prices and income. It also factors in government fiscal balances, monetary flows and interest and exchange rates. TIM projects the direct impacts on the economy's final demand, output, employment, price formation and sectoral income that result from various policy choices. These, in turn, permit an estimation of the effect of climate change policy and related impacts on the national economy.[28]

NextGrid and E3MC are capable of modelling electricity system mixes in Canada out to 2050 and base their results on optimization algorithms and constraints that are distinct to each model, utilizing data from a multitude of sources including Statistics Canada and ongoing collaboration with provinces and utilities. To the extent possible and where appropriate, underlying assumptions and application of the proposed Regulations have been aligned between E3MC and NextGrid to produce results from both models that can be used in tandem throughout the CBA. In the CBA, electricity system mix in the baseline scenario was modelled by E3MC, while electricity system mix in the policy scenario was modelled by NextGrid and E3MC. Specifically, NextGrid modelled the decisions that may be made by existing units that do not meet the CO_2 emissions intensity limit starting in 2035 (i.e., retire early, retrofit with CCS, or change operation regime to operate under the mass-based emission/duration flexibility), while E3MC modelled the decisions that may be made by all other units. NextGrid was also used to model and cost out new inter-provincial transmission lines that may be constructed in the regulatory scenario. Aside from those transmission lines, all other electricity system and economy-wide cost inputs used in the CBA were derived by E3MC. The CBA uses outputs from E3MC and NextGrid to present a distribution of impacts deemed attributable to the proposed Regulations, while acknowledging a variety of external economic and environmental changes that may occur over the analytical period by using conservative assumptions where appropriate and by testing alternative parameters in sensitivity analysis.

It is important to note that the proposed Regulations do not prescribe any particular compliance pathway onto any particular unit that does not meet the CO_2 emissions intensity limit starting in 2035. All results presented in the RIAS represent a modelled scenario indicating what may occur in response to the proposed Regulations based on reasonable constraints and assumptions (i.e., central case modelling). The central case scenario does not represent the only path that the electricity-generating sector could take to comply with the regulatory requirements and should not be interpreted as being more probable than other potential paths. Likewise, it is important to acknowledge the vast degree of uncertainty when modelling structural changes associated with economic decarbonization over a long-time horizon. A wide range of outcomes are ultimately possible, which could be driven by new or unanticipated technological development, alongside macroeconomic factors, demographic shifts and policy landscapes at all levels of government that may fundamentally alter baseline modelling.

Under the proposed Regulations, certain administrative costs to industry would begin in 2024 upon anticipated registration of the Regulations. Results from E3MC indicate that changes to Canada's electricity system mix and associated changes to system costs could begin as early as 2026 in anticipation of the CO_2 emission intensity limit coming into force starting in 2035. Because of this and

[28] The methodology for developing emissions scenarios in E3MC is described in Annex 7 of Chapter 5 in Canada's 8th National Communication and 5th Biennial Report (2022), and key data sources used within the model are presented in the 2023 report on Canadian Environmental Sustainability Indicators.

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Canada's goal to achieve net-zero emissions by 2050, the analytical timeframe chosen for the CBA is 2024 to 2050 (a 27-year period). Unless otherwise stated, all costs and monetized benefits are presented in 2022 constant dollars, discounted to base year 2023 at a discount rate of 2%. This is the near-term Ramsey discount rate now utilized by the Government of Canada when monetizing GHG reductions and is informed by the most current state of climate science (more information on this approach is presented in the benefits subsection). In all tables that follow, totals may not add up due to rounding.

Key modelling assumptions in the CBA

Some electricity generating units produce electricity for industrial use "behind-the-fence" (i.e., within an industrial facility). A subset of these industrial generation units sell a portion of the electricity they generate to a NERC-regulated electricity system. Under the proposed Regulations, any unit greater than or equal to 25 MW capacity that is connected to a NERC-regulated electricity system and is a net exporter of electricity as of 2035 (or the relevant compliance year) must comply with the 30 t/GWh annual CO_2 emission intensity standard, unless it meets all of the conditions related to one of the exceptions. The CBA modelling assumes that all industrial generation units with net exports to the electricity system in the baseline scenario would undertake the emission reduction related investments necessary to continue selling a portion of the electricity they generate to the electricity system in the regulatory scenario. By extension, the proportion of electricity that these industrial units produce for use "behind-the-fence" would also meet the CO_2 emission intensity standard. In the CBA, emissions reductions attributable to generation sold to the electricity system (from electric utilities and industrial generation units) are considered main benefits, while emissions reductions attributable to generation used "behind-the-fence" are considered co-benefits. By contrast, the CBA makes no distinction for costs incurred by electric utilities versus industrial generation units, in recognition that any investment that would be undertaken to meet the CO_2 emission intensity standard is considered a direct cost of the proposed Regulations regardless of where the generated electricity is ultimately used. Industrial generation units that are not connected to a NERC-regulated electricity system and only generate electricity for use "behind-the-fence" are not subject to the proposed Regulations and are therefore out of scope of the CBA.

For the purposes of analysis, the Department modelled into the baseline scenario, inter-provincial transmission lines (or interties) including those that are not yet constructed (e.g. the Atlantic Loop). Regional interties are considered to be a key compliance strategy for coal-dependent provinces to meet the requirements of the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations as amended in 2018, and are not considered incremental to the proposed Regulations. Modelling indicates that regional interties in the Atlantic region are the lowest cost option of complying with the proposed Regulations.

The baseline scenario also includes federal funding policies and programs related to electricity system infrastructure investments. Specifically, the baseline scenario accounts for an abstraction of the Investment Tax Credit (ITC[29]) for Clean Technology that was announced in the 2022 Fall Economic Statement, by reducing the marginal capital cost of greenfield construction (per MW) of qualifying technologies by 30% in 2023 through to 2031, then phasing the credits out linearly from 2032 to 2035. The modelled ITC affects the relative cost that industry faces to construct qualifying non-emitting electricity system technologies versus emitting electricity system technologies, thereby increasing the attractiveness of investments in non-emitting capacity in the baseline scenario relative to what it has been historically. The modelled ITC was applied to nuclear, pumped hydro, small hydro, onshore wind, offshore wind, solar PV, wave and storage, but not to emitting technologies that implement a CCS system. The central case modelling did not incorporate the full range of federal supports that will become available to

[29] The ITC published in the FES 2022 would also incentivize companies to create jobs. Those that adhere to certain labour conditions will be eligible for the full 30 per cent credit under the ITC, while those that do not will only be eligible for a credit of 20 per cent. Labour conditions would include paying prevailing wages based on local labour market conditions and ensuring that apprenticeship training opportunities are being created. https://www.budget.canada.ca/fes-eea/2022/report-rapport/chap2-en.html#a16

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the electricity generation sector in Canada. As more details around the new Clean Electricity ITC and its application become available, alongside additional new measures announced in Budget 2023, the final design of the Clean Technology ITC, the ITC on CCS and any future federal funding decisions (e.g., SIF NZA), future central case modelling would be adjusted to align with that treatment. Such federal funding decisions are expected to reduce the scale of incremental impacts assessed for the proposed Regulations (i.e., lower costs and lower benefits), as additional actions to reduce GHG emissions in the electricity generation sector would be expected to occur in the baseline scenario.

Rates in Nova Scotia and New Brunswick are expected to increase in the future under the baseline scenario. In addition to measures included in the 2022 Fall Economic Statement and Budget 2023 that support the decarbonization of electricity, the federal government has offered funding to build out transmission lines that will contribute to the efforts to mitigate impacts on electricity rates in the region. Reducing the expected rate increases under the baseline scenario also lowers the proposed Regulation's overall impact on rates.

From a CBA perspective, it is worth noting that any government expenditure with respect to federal funding incentives would constitute a cost transfer from industry (and by extension, consumers of electricity) to the general tax base. The central case modelling accounts for incremental uptake of federal funding by first projecting the electricity system mix that would be constructed in the baseline and regulatory scenarios with the modelled ITC in place, then determining the incremental government expenditure associated with those investments.

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Electricity system mix

Canada's electricity system mix can be characterized on two bases: capacity and generation. Capacity refers to the amount of electricity a unit is capable of generating (e.g., installed capacity expressed in MW), whereas generation refers to the actual amount of electricity generated by a unit (e.g., capacity utilization expressed in GWh). Generating units are not always operated at full capacity. For example, a wind unit would generate below its capacity when wind speeds are low- and a back-up unit would only generate at capacity when required for reliability. E3MC modelling indicates that Canada's electric utility sector (excluding all industrial generation units) would take on the following capacity characteristics in the baseline scenario (Table 4) versus in the regulatory scenario (Table 5):

Table 4. Electricity system mix by technology type (capacity basis), baseline scenario

Technology type	2025	2030	2035	2040	2045	2050
Emitting*	17.9%	16.4%	14.1%	13.4%	12.9%	12.6%
Emitting with CCS	0.1%	0.1%	0.3%	0.4%	0.5%	0.5%
Nuclear	8.8%	6.1%	5.1%	4.8%	4.6%	4.3%
Hydro	53.1%	43.1%	39.2%	37.7%	37.0%	36.7%
Other non-emitting**	20.1%	34.3%	41.3%	43.7%	45.1%	45.9%
Total capacity (%)	100%	100%	100%	100%	100%	100%
Total capacity (MW)	149,244	183,907	220,858	234,536	243,420	258,442
Storage (MW)	2,701	4,877	6,607	7,285	7,832	9,021

* For Tables 4 through 7, "emitting" refers OGCT, OGCC, small OGCC, OG steam, coal, biomass and waste, which may be different from what constitutes emitting under the NIR.

** For Tables 4 through 7, "other non-emitting" refers to onshore wind, offshore wind, solar PV, geothermal and wave.

Table 5. Electricity system mix by technology type (capacity basis), regulatory scenario

Technology type	2025	2030	2035	2040	2045	2050
Emitting	17.9%	15.6%	9.0%	8.0%	6.7%	6.5%
Emitting with CCS	0.1%	0.9%	3.8%	4.2%	4.9%	4.8%
Nuclear	8.8%	6.2%	5.4%	5.0%	5.1%	5.1%
Hydro	53.1%	43.1%	39.6%	38.0%	37.6%	37.6%
Other non-emitting	20.1%	34.3%	42.2%	44.8%	45.6%	46.0%
Total capacity (%)	100%	100%	100%	100%	100%	100%
Total capacity (MW)	149,244	183,725	219,876	240,008	247,801	260,301
Storage (MW)	2,701	5,052	6,887	7,745	8,658	9,931

Likewise, E3MC suggests that Canada's electric utility sector (excluding all industrial generation units) would take on the following generation characteristics in the baseline scenario (Table 6) versus in the regulatory scenario (Table 7):

Table 6. Electricity system mix by technology type (generation basis), baseline scenario

Technology type	2025	2030	2035	2040	2045	2050
Emitting	14.3%	9.9%	7.1%	6.9%	6.3%	6.2%*
Emitting with CCS	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Nuclear	10.9%	9.7%	9.7%	9.0%	8.7%	8.3%
Hydro	62.0%	56.4%	52.9%	51.5%	50.7%	49.9%
Other non-emitting	12.6%	23.8%	30.2%	32.5%	34.1%	35.6%
Total generation (%)	100%	100%	100%	100%	100%	100%
Total generation (GWh)	620,300	685,808	772,314	807,363	836,810	885,514

* of this proportion, 9% of emitting generation in 2050 is attributable to biomass and waste

Table 7. Electricity system mix by technology type (generation basis), regulatory scenario

Technology type	2025	2030	2035	2040	2045	2050
Emitting	14.3%	9.7%	3.8%	1.7%	0.8%	1.1%*
Emitting with CCS	0.1%	0.3%	1.1%	0.8%	1.2%	1.1%
Nuclear	10.9%	9.7%	10.1%	9.5%	9.2%	9.3%
Hydro	62.0%	56.4%	54.0%	53.5%	53.5%	52.5%
Other non-emitting	12.6%	23.8%	31.1%	34.5%	35.3%	36.1%
Total generation (%)	100%	100%	100%	100%	100%	100%
Total generation (GWh)	620,300	685,689	774,404	810,726	838,254	886,766

* of this proportion, 42% of emitting generation in 2050 is attributable to biomass and waste

In absence of the proposed Regulations (Table 6), Canada's electricity system would have been expected to reduce unabated emitting generation from 14.3% in 2025 to 6.2% in 2050 and would have been expected to increase non-emitting generation from 85.5% in 2025 to 93.7% in 2050. By contrast, under the proposed Regulations (Table 7), Canada's electricity system would be expected to reduce unabated emitting generation from 14.3% in 2025 to 1.1% in 2050 and would be expected to increase non-emitting generation from 85.5% in 2025 to 97.9% in 2050.

Benefits

The proposed Regulations would reduce the amount of GHGs emitted by electricity generating units across Canada, in the form of carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O), with CO_2 being the most significant. Reductions in emissions of these gases would result in avoided global damage from climate change. The proposed Regulations would also reduce the amount of air pollutants emitted by electricity generating units, including nitrogen oxides (NO_X), sulfur oxides (SO_X), primary particulate

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matter less than 2.5 microns in width ($PM_{2.5}$) and mercury (Hg). Reductions of these air pollutants may result in improvements to localized air quality, depending on the geographical and meteorological features of the emission sites, which may in turn result in health benefits and environmental benefits.

As emitting sources of electricity generation are replaced by low or non-emitting sources, the proposed Regulations would also result in cost-savings over time to the electricity sector in the form of avoided fuel usage, variable operations and maintenance and refurbishment.

Each of these benefits are described in detail in the subsections below.

Avoided global damage from climate change

Using outputs from E3MC, the CBA estimates that the proposed Regulations would result in the reduction of 272 Mt of GHGs (expressed as CO_2e) from electricity generation sold to a NERC-regulated electricity system, as well as the reduction of 70 Mt of GHGs from electricity generation used behind the fence, for total reductions of nearly 342 Mt over the 27-year (2024 to 2050) analytical period (Table 8).

Table 8. Incremental GHG reductions (expressed as kilotonnes of CO_2e*)

Description	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annual average (n=27)
CO_2 (electricity system)	-1,112	13,024	75,308	87,058	93,811	268,088	9,929
CH_4 (electricity system)	-5	124	643	577	568	1,907	71
N_2O (electricity system)	-12	83	539	566	589	1,765	65
CO_2 ("behind-the-fence")	2,293	5,508	20,492	20,689	20,544	69,527	2,575
CH_4 ("behind-the-fence")	1	31	126	54	26	238	9
N_2O ("behind-the-fence")	12	28	106	104	101	350	13
Main benefits: GHG reductions attributable to electricity generation sold to the electricity system**	-1,129	13,231	76,490	88,201	94,968	271,761	10,065
Co-benefits: GHG reductions attributable to electricity generation used "behind-the-fence"***	2,306	5,567	20,725	20,847	20,671	70,116	2,597
Total GHG reductions	1,177	18,798	97,215	109,048	115,640	341,877	12,662

* CH_4 and N_2O were converted to CO_2e using the global warming potential factors 25 and 298, respectively.
** This subtotal represents the sum of CO_2 (electricity system), CH_4 (electricity system) and N_2O (electricity system).
*** This subtotal represents the sum of CO_2 ("behind-the-fence"), CH_4 ("behind-the-fence") and N_2O ("behind-the-fence").

The avoided global damage from climate change associated with these GHG reductions can be monetized using social cost estimates for each pollutant. In November 2022, the United States Environmental Protection Agency (US EPA) released its draft Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances (the draft US EPA Report), in which social cost (SC) methodologies and values have been updated and presented for CO_2, CH_4 and N_2O. In April 2023, the Department published draft SC guidance for Canada in alignment with the SC-GHG values proposed by the US EPA. A subset of Canadian SC-GHG values from that guidance document are presented in Table 9.

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Table 9. Annual SC-CO_2, SC-CH_4 and SC-N_2O values in select years (2021 CAD, $/tonne, discounted to the relevant index year at 2%)*

Index year	SC-CO_2	SC-CH_4	SC-N_2O
2020	$247	$2,107	$69,230
2025	$271	$2,589	$77,066
2030	$294	$3,073	$84,903
2035	$317	$3,634	$92,894
2040	$341	$4,194	$100,886
2045	$367	$4,803	$109,902
2050	$394	$5,410	$118,919

* The SC values for CH_4 and N_2O incorporate their own concept of global warming potential within the calculations. As such, to use these SC values within the CBA, they must be multiplied by the tonnage reductions in CH_4 and N_2O, not by the tonnage reductions in those pollutants expressed as CO_2e.

The Canadian SC-GHG values in Table 9 are a reflection of the most recent state of climate science. As explained in the draft US EPA Report, the updated SC-GHG values were derived from the interaction of four modules: socioeconomics and emissions, climate, damages and discounting. The socioeconomic and emissions module relies on a new set of probabilistic projections for population, income and GHG emissions developed under the Resources for the Future Social Cost of Carbon Initiative. The climate module relies on the Finite Amplitude Impulse Response model (a widely used Earth system model recommended by the National Academies), which captures the relationships between GHG emissions, atmospheric GHG concentrations and global mean surface temperature. The socioeconomic projections and outputs of the climate module are used as inputs to the damage module to estimate monetized future damages from temperature changes. The discounting module discounts the stream of future climate damages back to the year of emissions using a set of dynamic discount rates that encompass a great deal of uncertainty. As noted in the draft US EPA Report, the modules use conservative methodological assumptions and are therefore likely to underestimate the marginal damages from GHG pollution.

The CBA converted the Canadian SC-GHG values presented in Table 9 to 2022 constant dollars using a conversion factor of 1.06898 (derived from the Consumer Price Index estimates in E3MC), then multiplied those values by the tonnage reductions in each pollutant (not in CO_2e terms) summarized in Table 8, before discounting the results back to base year 2023 at 2%. As seen in Table 10, the proposed Regulations would result in $87.5 billion of avoided global damage from climate change over the 27-year analytical period, of which $69.5 billion would be attributable to electricity generation sold to the electricity system.

Table 10. Avoided global damage from climate change (millions of dollars)

Description	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)
CO_2 (electricity system)	-306	3,477	19,809	22,347	23,440	68,767	3,321
CH_4 (electricity system)	-1	15	81	76	76	248	12
N_2O (electricity system)	-3	22	140	145	148	453	22
CO_2 (“behind-the-fence”)	632	1,478	5,392	5,313	5,134	17,949	867
CH_4 (“behind-the-fence”)	0.1	4	16	7	4	30	1
N_2O (“behind-the-fence”)	3	7	28	27	26	90	4
Main benefits: Climate change benefits attributable to electricity generation	-310	3,514	20,030	22,568	23,665	69,468	3,355

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sold to the electricity system*							
Co-benefits: Climate change benefits attributable to electricity generation used “behind-the-fence”**	635	1,489	5,436	5,346	5,163	18,069	873
Total climate change benefits	325	5,003	25,466	27,914	28,828	87,537	4,227

* This subtotal represents the sum of CO_2 (electricity system), CH_4 (electricity system) and N_2O (electricity system).
** This subtotal represents the sum of CO_2 (“behind-the-fence”), CH_4 (“behind-the-fence”) and N_2O (“behind-the-fence”).

As noted in the description section of the RIAS, a compliance flexibility would be available until 2040 for any unit that commissions a CCS system, which would allow those units to operate up to 40 t/GWh for up to seven years or until December 31, 2039, whichever comes first, as long as the unit has demonstrated that it can operate at or below 30 t/GWh for two specified periods of time during a year. The CBA modelling assumes that such units would be capable of meeting 30 t/GWh by 2035 and therefore does not model use of this compliance flexibility. It should be noted that, depending on the uptake of the compliance flexibility among CCS equipped units, GHG reductions and associated monetized benefit, fuel cost-savings and variable O&M costs for these units may be slightly overestimated in the years prior to 2040. However, since the emissions intensity standard for natural gas units (the majority of CCS users) in the baseline scenario is 420 to 550 t/GWh as per the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*, dropping from those baseline standards to 40 t/GWh in the policy scenario (rather than 30 t/GWh) for a limited number of years is not expected to significantly reduce the incremental climate change benefits depicted in Table 10.

Potential health benefits

Using outputs from E3MC, the CBA estimates that the proposed Regulations would result in air pollutant emission reductions from electricity generation sold to the electricity system as well as from electricity generation used “behind-the-fence”. Table 11 provides a breakdown of these reductions by pollutant over the 27-year analytical period.

Table 11. Incremental air pollutant emission reductions, by pollutant (tonnes)

Description	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annual average (n=27)
NO_X (electricity system)	2,154	25,140	131,363	95,244	90,705	344,605	12,763
SO_X (electricity system)	9,277	6,942	42,663	18,965	18,835	96,682	3,581
$PM_{2.5}$ (electricity system)	44	1,695	8,557	7,858	7,983	26,138	968
Hg (electricity system)	0.0108	0.0625	0.3137	0.3140	0.3138	1.0149	0.0376
NO_X (“behind-the-fence”)	1,750	3,891	17,863	28,040	27,952	79,496	2,944
SO_X (“behind-the-fence”)	2,033	2,315	8,186	23,445	23,220	59,200	2,193
$PM_{2.5}$ (“behind-the-fence”)	14	17	158	544	534	1,268	47
Hg (“behind-the-fence”)	0.0003	0.0011	0.0042	0.0043	0.0043	0.0142	0.0005

The distribution of these incremental air pollutant emission reductions by province over the analytical period is presented in Table 12.

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Table 12. Incremental air pollutant emission reductions from 2024 to 2050, by province (tonnes)*

Province	NO_X	SO_X	$PM_{2.5}$	Hg
NL	591	63	7	0.0000
PE	146	185	9.5	0.0000
NS	27,816	15,039	-224	0.0154
NB	4,112	29,004	65	0.0000
QC	0.0	0.0	0.0	0.0000
ON	225,718	-55	24,412	0.0001
MB	0.0	0.0	0.0	0.0000
SK	50,821	68,513	1,900	0.8363
AB	103,914	41,712	1,064	0.0150
BC	10,978	1,421	172	0.1621
YT	0.6	0	0	0.0000
NT	3.7	0	0.1	0.0000
NU	2	0	0	0.0000
Total	424,101	155,882	27,406	1.0290

* E3MC accounts for air pollutant emissions from electricity generation as well as a relatively small amount of air pollutant emissions from operational processes including distribution. It is possible for some technology types to be associated with zero air pollutant emissions from electricity generation but positive air pollutant emissions from operational processes. The totals presented in this table represent the sum of both sources of air pollutant emissions.

As seen in Table 12, Alberta, Saskatchewan, Ontario, Nova Scotia and New Brunswick are the provinces that would incur the greatest amount of air pollutant emission reductions, largely attributable to the switch from unabated natural gas plants to low, or non-emitting sources of electricity generation. Depending on the location of these air pollutant emission reductions, the proposed Regulations would be expected to result in improvements to localized air quality. It should be noted that biomass, biomass CCS and NG CCS are associated with air pollutants emissions from electricity generation. As such, provinces with significant incremental buildout of these technologies may experience less overall incremental air pollutant reductions than provinces who rely more on non-emitting technology types.

Air pollution is recognized globally as a major contributor to the development of disease and premature death and is a key environmental risk factor to human health in Canada. Exposure to air pollution increases the risk of premature mortality from heart disease, stroke and lung cancer, as well as the risk of adverse respiratory and cardiovascular diseases. Children, the elderly and individuals with underlying health conditions are particularly vulnerable to the adverse effects of air pollution. Moreover, scientific evidence shows that adverse health effects occur at very low concentrations for many pollutants, with no indication of a threshold below which there are no risks. Therefore, a small decrease in air pollution is associated with a reduction in the risk of adverse health outcomes for exposed populations. The Department of Health estimates that in 2015, air pollution from electricity generating units contributes to about 150 premature deaths per year in Canada as well as many non-fatal outcomes, with a total cost of $1.2 billion per year (2015 constant dollars).[30] While negative health impacts are expected to be significantly mitigated by the *Regulations Amending the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*, the proposed Regulations would be expected to also reduce adverse health impacts.

The proposed Regulations would also result in 1,029 kilograms of mercury emissions reductions, the majority of which would be located in southern Saskatchewan. Exposure to mercury is associated with a wide range of adverse health effects in humans (notably, the nervous system is sensitive to the toxicity of mercury), with developing foetuses and children being the most susceptible to these adverse health effects.

[30] The 2015 study Health impacts of air pollution from transportation, industry and residential sources in Canada.

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Impacts to air quality and associated health benefits have not been quantified nor monetized in this analysis. However, air pollutant emission reductions associated with the proposed Regulations would be expected to reduce the risk of adverse health outcomes for affected populations, which would accrue as monetized benefits into the future.

Potential environmental benefits

To the extent that the reductions in air pollution depicted in Table 12 improve localized air quality, the proposed Regulations may also reduce environmental harms in the form of improved visibility, avoided cleaning costs for surface soiling, improved yield for crop producers, improved health of forest ecosystems and reduced risk of illness or premature death within sensitive wildlife or livestock populations, depending on what is located in proximity to the emission site. Impacts to air quality and associated environmental benefits have similarly not been quantified nor monetized in this analysis.

Fuel cost-savings

Emitting plant types require a fuel source to generate electricity (e.g., natural gas, heavy fuel oil, light fuel oil, liquefied petroleum gas, biomass, or waste). By contrast, non-emitting plant types use renewable energy sources such as water, wind, heat or the sun to generate electricity, all of which are provided by the natural environment. With the exception of plants that implement CCS,[31] the switch from emitting plant types to low or non-emitting plant types under the proposed Regulations would significantly reduce operational costs to the electricity generation sector with respect to fuel. Using outputs from E3MC, the CBA estimates that the proposed Regulations would result in a total of $13.5 billion in fuel savings for electricity generating units over the 27-year analytical period. The distribution of these savings by province is presented in Table 13.

Table 13. Incremental fuel cost-savings by province (millions of dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)
NL	0	54	237	103	48	442	21
PE	0	4	8	1	0	13	1
NS	-5	147	651	661	532	1,986	96
NB	4	81	279	64	130	558	27
QC	0	6	28	26	24	84	4
ON	-23	245	1,484	1,798	1,353	4,858	235
MB	0	0	0	0	0	0	0
SK	-2	100	632	718	701	2,148	104
AB	2	135	899	1,035	1,141	3,211	155
BC	0	13	74	69	66	222	11
YK	0	0	0	0	0	0	0
NT	0	0	0	0	0	0	0
NU	0	0	0	0	0	0	0
Total	-25	785	4,292	4,475	3,994	13,522	653

* Fuel expenditure increases in the early years of the analytical period due to changes in generation versus imports, as well as fuel use from the new electricity system technologies that are modelled to be constructed during this period (i.e., NG CCS and biomass). This observation is also true for variable O&M.

[31] Plant types with CCS are able to abate the vast majority of their GHG emissions by capturing and storing those emissions (typically underground) instead of releasing them into the atmosphere. However, these CCS technologies come with trade-offs to fuel usage and associated air pollution. Specifically, plant types with CCS use more fuel to generate one MWh of electricity than their unabated counterparts, in order to power the systems that sequester the GHG emissions. Since more fuel is being burned, a proportionate increase in air pollutants is released into the atmosphere (because CCS technologies only capture and store GHGs, not air pollutants). This phenomenon is sometimes referred to as the “energy penalty”.

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A detailed example of how fuel cost-savings were calculated will be made available upon request by the Department in the coming months.

Variable operations and maintenance cost-savings

When considering all types of low or non-emitting plants, the average cost to operate and maintain those units on a variable basis (per MWh generation) is lower than that of unabated emitting plant types. As such, the switch from emitting plant types to low or non-emitting plant types under the proposed Regulations would tend to reduce variable operations and maintenance (O&M) costs to the electricity sector. Using outputs from E3MC, the CBA estimates that the proposed Regulations would result in a total of $1.4 billion in O&M cost-savings over the 27-year analytical period. The distribution of this cost-savings by province is presented in Table 14.

Table 14. Incremental variable O&M cost-savings by province (millions of dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)
NL	0	2	9	3	2	16	1
PE	0	0	1	1	1	3	0
NS	0	8	26	30	29	93	4
NB	1	10	26	10	19	67	3
QC	0	0	-1	-1	0	-2	0
ON	-3	32	147	166	140	482	23
MB	0	0	0	0	0	0	0
SK	0	17	85	63	40	205	10
AB	-5	23	264	185	182	650	31
BC	-1	-8	-25	-32	-45	-111	-5
YK	0	0	0	0	0	0	0
NT	0	0	0	0	0	0	0
NU	0	0	0	0	0	0	0
Total	-7	83	531	426	368	1,402	68

A detailed example of how O&M savings were calculated will be made available upon request by the Department in the coming months.

Refurbishment cost-savings

Refurbishment costs are periodic capital costs undertaken at the end of a unit's operational lifetime, spent to return a unit to a condition similar to that at the time of its original commissioning. E3MC does not apply the concept of operating lifetime to units and thus, many units in the model are assumed to continue to operate regardless of their age. To ensure that periodic refurbishment costs are reflected in the analysis, the CBA places an extra cost on units in the year that they would reach the end of their operating lifetime. Once that extra cost is applied, the CBA models that unit operating for another operating lifetime, after which the extra cost would be incurred again. This cycle is repeated from a unit's online date to the end of the analytical period in 2050.

The CBA conceptualizes refurbishment cost as the "brownfield" cost of replacing an old unit with a new unit of equivalent type and capacity. Brownfield means that a new unit is constructed using an old unit's infrastructure as a basis, which is much less costly than constructing a new unit in a new area ("greenfield"). The most significant cost difference between brownfield and greenfield construction is the presence of fuel feedstock lines and electricity transmission lines that connect the unit upstream and downstream. The CBA makes a conservative assumption that the cost of brownfield construction is one-third that of greenfield construction for any given plant type. This conservative assumption likely understates the magnitude of cost-savings that would be realized.

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Under the proposed Regulations, provinces with relatively high emitting capacity in the baseline scenario are expected to see foregone refurbishment costs in the regulatory scenario as units retire, with two exceptions. The first exception is unabated natural gas plants that retrofit with CCS, which are assumed to remain on their original refurbishment schedules but would now incur higher brownfield costs at the end of their operating lifetimes. The second exception is electricity storage, which has a shorter operating lifetime than other electricity system technologies. Overall, the CBA modelling estimates that the proposed Regulations would result in a total of $55 million of incremental refurbishment cost-savings over the 27-year analytical period. The distribution of refurbishment cost-savings by province is presented in Table 15.

Table 15. Incremental refurbishment cost-savings by province (millions of dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)
NL	0	0	11	29	0	41	2
PE	0	0	0	0	0	0	0
NS	0	0	-24	0	0	-24	-1
NB	0	0	0	0	0	0	0
QC	0	30	-6	3	0	27	1
ON	0	48	101	0	0	149	7
MB	0	0	0	0	0	0	0
SK	0	0	-5	-85	0	-90	-4
AB	99	0	0	-219	-78	-198	-10
BC	0	0	111	-9	49	151	7
YK	0	0	0	0	0	0	0
NT	0	0	0	0	0	0	0
NU	0	0	0	0	0	0	0
Total	99	77	189	-281	-28	55	3

Costs

As emitting sources of electricity generation are replaced by low or non-emitting sources, the proposed Regulations would result in incremental costs related to constructing new generation and storage capacity, constructing new transmission lines, fixed operations and maintenance, residual value of capital on early retirements and increased net import expenditure, alongside increased administrative and government costs.

Each of these costs are described in detail in the subsections below.

Capital costs for new electricity system capacity

New electricity system capacity denotes the year-over-year increase in generation and storage capacity required in both the baseline scenario and the regulatory scenario to meet energy demand and other constraints. The proposed Regulations would result in less new capital buildout of emitting plant types and more new capital buildout of low or non-emitting plant types. Most non-emitting plant types have a higher capital cost per MW capacity than their emitting counterparts. Emitting plant types with CCS also have a higher capital cost per MW capacity than their unabated counterparts. Accordingly, the cost-savings associated with forgone buildout of new emitting capacity are generally smaller than the costs associated with buildout of new low or non-emitting capacity.

Using outputs from E3MC, the CBA estimates that the proposed Regulations would result in a total of $53.7 billion in incremental capital costs to the electricity generation sector for new electricity system capacity over the 27-year analytical period. Total capital cost distributed by province is presented in Table 16 and annualized average capital cost by technology type and province is presented in Table 17.

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Table 16. Incremental capital cost for new electricity system capacity by province (millions of dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)
NL	0	0	780	210	1,235	2,225	107
PE	0	0	0	0	0	0	0
NS	1,648	3,730	642	743	-623	6,140	297
NB	0	0	1,405	4,340	0	5,745	277
QC	2	294	64	0	-79	281	14
ON	-63	3,900	10,251	-1,225	217	13,081	632
MB	0	0	0	0	0	0	0
SK	340	1,241	2,467	30	2,628	6,707	324
AB	2,607	14,606	683	357	-1,340	16,914	817
BC	0	1,626	953	88	-93	2,574	124
YK	0	0	0	0	0	0	0
NT	0	0	0	0	0	0	0
NU	0	0	0	0	0	0	0
Total	4,534	25,398	17,246	4,543	1,946	53,667	2,592

Table 17. Annualized average (n=27) capital cost for new electricity system capacity by technology type and province (millions of dollars)

	NL	NS	NB	QC	ON	SK	AB	BC	Total
OGCT	0	43	-13	0	-2	-19	-43	0	-34
OGCC	0	0	-25	0	-4	-36	-82	0	-147
Small OGCC	0	-14	-28	0	-4	-40	-90	0	-177
NG CCS*	0	0	0	0	0	181	820	0	1,001
Nuclear	0	0	281	0	0	204	196	0	681
Base hydro	26	27	38	0	0	4	55	1	151
Peak hydro	0	0	0	14	452	0	0	94	560
Small hydro	21	0	0	-3	95	7	-84	10	45
Biomass	12	138	25	0	10	3	48	2	238
Biomass CCS	0	0	0	0	105	9	12	11	138
Onshore wind	18	73	-0.1	2	-25	4	-24	5	52
Offshore wind	27	19	-0.04	0	0	0	0	0	46
Solar PV	-0.1	2	0	-0.01	4	8	5	0.1	19
Storage	4	8	0	1	2	-1	4	2	19
Total	107	297	277	14	632	324	817	124	2,592

* Capital cost expenditure with respect to NG CCS has two components: new build of NG CCS and retrofit of existing natural gas units to deploy CCS.

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As depicted in Table 16, Prince Edward Island, Manitoba, Yukon, Northwest Territories and Nunavut are not expected to undertake any significant buildout of electricity system technologies in response to the proposed Regulations, while significant new investment is expected in Alberta, Ontario, Saskatchewan, Nova Scotia and New Brunswick. As depicted in Table 17, the majority of capital cost for those provinces would be attributable to the buildout of biomass in Nova Scotia, nuclear in New Brunswick, peak hydro in Ontario, nuclear in Saskatchewan and NG CCS in Alberta. Overall, the proposed Regulations would result in decreased new capital buildout of unabated emitting generation technologies (OGCT, OGCC and small OGCC), paired with increased new buildout of all other types of electricity system technologies.

A detailed example of how capital costs for new electricity system capacity was calculated will be made available upon request by the Department in the coming months. The cost to government for incremental

uptake of the modelled ITC associated with the capital costs to the electricity generation sector denoted in Table 16 is presented in the government cost subsection.

Capital cost for new transmission lines

NextGrid modelling indicates that minimizing the system-wide costs of the proposed Regulations while ensuring reliability would entail provinces constructing certain interties to facilitate the movement of domestically-produced electricity. Using outputs from NextGrid, the CBA estimates that the proposed Regulations would result in a total of $6.7 billion of incremental capital costs for new inter-provincial transmission lines over the 27-year analytical period. The CBA assumes that the capital cost of all new transmission lines would be shared evenly between the two provinces that the line connects. The distribution of these infrastructure costs by province is presented in Table 18.

Table 18. Incremental capital cost for new transmission lines by province (millions of dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)
NL	0	0	0	0	0	0	0
PE	0	79	0	0	0	79	4
NS	0	0	0	0	0	0	0
NB	0	79	0	0	0	79	4
QC	0	0	558	0	0	558	27
ON	0	443	597	52	291	1,383	67
MB	0	443	38	70	486	1,038	50
SK	0	437	0	18	196	651	31
AB	0	1,132	0	374	146	1,653	80
BC	0	694	0	374	146	1,215	59
YK	0	0	0	0	0	0	0
NT	0	0	0	0	0	0	0
NU	0	0	0	0	0	0	0
Total	0	3,309	1,193	889	1,265	6,656	321

Since the development and implementation of a new inter-provincial transmission line requires many years to become operational, all interties that would come online between 2024 and 2030 are already planned and therefore, are not considered incremental to the proposed Regulations. The costs in Table 18 were calculated by multiplying the modeled transmission capacity (MW) by the estimated marginal transmission capital cost ($/MW), as denoted in Table 19. Variance in marginal transmission capital cost is attributable to different line distances (kilometers) as well as provincial differences in geography and permitting.

Table 19. Incremental transmission capacity and estimated marginal transmission capital cost

Connected provinces	Modeled transmission capacity (MW)	Average marginal transmission capital cost ($/MW, millions of dollars, 2022 constant dollars, undiscounted)
NB – PE	125	1.6
ON – QC	2,000	0.8
MB – ON	666	3.6
MB – SK	110	3.3
SK – MB	108	3.3
AB – SK	300	3.7
BC – AB	2,100	1.6

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The proposed Regulations are not expected to create an incentive to expand interties to the Territories, as most generating units in the Territories are less than 25 MW in capacity and not connected to a NERC-regulated electricity system and therefore fall outside the scope of the proposed Regulations. Of note, the CBA does not account for any potential new buildout of intra-provincial transmission lines that may be required to connect new infrastructure buildout to the electricity system, as it is assumed that new infrastructure would make use of existing intra-provincial transmission lines.

Fixed operations and maintenance cost

When considering all types of low, or non-emitting plants, the average cost to operate and maintain on a fixed basis (per MW capacity) is higher than that of unabated emitting plant types. As such, the switch from emitting plant types to low or non-emitting plant types under the proposed Regulations would tend to increase fixed O&M costs to the electricity sector. E3MC suggests that the proposed Regulations would result in a total of $6.4 billion in fixed O&M costs over the 27-year analytical period. The distribution of these costs by province is presented in Table 20.

Table 20. Incremental fixed O&M cost by province (millions of dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)
NL	0	-4	28	68	165	257	12
PE	0	0	-2	-2	-2	-6	0
NS	30	60	146	219	178	633	31
NB	0	0	26	511	463	1,001	48
QC	0	3	19	12	6	40	2
ON	-3	-38	200	159	31	350	17
MB	0	0	0	0	0	0	0
SK	5	62	182	253	301	802	39
AB	57	490	1,045	966	799	3,357	162
BC	0	-16	-24	-7	-10	-57	-3
YK	0	0	0	0	0	0	0
NT	0	0	-2	-2	-2	-6	0
NU	0	0	0	0	0	0	0
Total	89	556	1,619	2,179	1,930	6,372	308

A detailed example of how fixed O&M costs were calculated will be made available upon request by the Department in the coming months.

Residual value of capital on early retirements

As previously noted, the proposed Regulations do not prescribe any particular compliance pathway onto any particular unit that would not meet the CO_2 emissions intensity limit starting in 2035 and all results presented in the CBA represent a modelled scenario indicating what may occur in response to the proposed Regulations under a central case. Within this central case, NextGrid modelled the decisions that may be made by existing units that do not meet the CO_2 emissions intensity limit starting in 2035 (i.e., retire early, retrofit with CCS, or change operation regime to operate under the mass-based emission/duration flexibility), while E3MC modelled the decisions that may be made by all other units.

Under the central case modelling, the majority of unabated emitting units (56%) would continue to operate in a limited manner under the mass-based emission/duration flexibility in the year that the CO_2 emissions intensity limit begins applying to those units to provide backup capacity to the electricity system for reliability purposes. Another proportion of unabated emitting units (35%) would continue to operate by implementing a CCS system to meet the CO_2 emissions intensity limit. A minority of affected emitting

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units (9%) would retire earlier than they otherwise would have in the absence of the proposed Regulations.

Using outputs from E3MC to monetize the retirement compliance pathway set out by NextGrid, the CBA estimates that the residual value of capital on early retirements would total $1.3 billion over the 27-year analytical period (or a 27-year annualized average of $65 million), all of which would be expected to occur in 2035. These costs were estimated by first multiplying the capacity (kW) of each retired unit in 2034 (i.e., their last year of full production) by the marginal generation capacity capital cost ($/kW) of those units in 2035. This represents the greenfield cost to construct a new unit of equivalent capacity in the year of retirement. To transform this total value into the residual value of retired capital, those greenfield costs were then multiplied by the fraction of operating lifetime remaining for each unit, based on their online date as a proxy for their commissioning date.

Insofar that other capital would need to be constructed (or imports would need to rise) to replace the generation provided by the units that would retire early, assigning a cost to early retirements may constitute double-counting from a CBA perspective. However, this cost is retained within the CBA to recognize industry costs that may arise from unpaid debt servicing on assets that cease to operate.

Increased international net import expenditure

Using outputs from E3MC, the CBA estimates that incremental international export revenue would decrease by $5.6 billion (2% decrease from the baseline scenario), while incremental import expenditure would increase by $6 million (0.01% increase from the baseline scenario). Accordingly, net import expenditure (import expenditure minus export revenue) from international trade would increase by $5.6 billion over the 27-year analytical period. The distribution of incremental net import expenditure by province is presented in Table 21.

Table 21. Incremental international net import expenditure by province (millions of dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)
NL	0	0	0	0	0	0	0
PE	0	0	0	0	0	0	0
NS	0	0	0	0	0	0	0
NB	-12	-41	-85	-118	-54	-309	-15
QC	69	449	-1,274	998	1,758	2,000	97
ON	-41	534	-972	-686	-202	-1,365	-66
MB	12	390	1,296	1,488	752	3,938	190
SK	0	5	5	-58	-54	-103	-5
AB	0	3	21	26	20	70	3
BC	13	17	-110	303	1,127	1,350	65
YK	0	0	0	0	0	0	0
NT	0	0	0	0	0	0	0
NU	0	0	0	0	0	0	0
Total	41	1,357	-1,118	1,953	3,348	5,581	270

A detailed example of how fuel net export revenue was calculated will be made available upon request by the Department in the coming months. The CBA assumes that there would be no significant difference in the average emissions intensity of electricity generated in Canada versus that generated in the US for the purpose of bilateral trade. Carbon leakage is not expected to constitute a risk to the achievement of the avoided climate change damages presented in the benefits subsection.

The CBA considers that any impacts the proposed Regulations may have on domestic net import expenditure are transfers and are therefore analyzed in the distributional analysis section. It should be

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noted that, subject to some constraints, trade is an alternative to capital buildout and would be selected when the latter is relatively more expensive. As such, provinces that are expected to increase their international or domestic net imports would also experience forgone increased capital costs for new electricity generation capacity. In other words, should the estimated trade impacts not occur as modelled, then the incremental capital cost for new electricity system capacity depicted in Table 16 would increase proportionately for import-dependent provinces.

Administrative costs

As noted in the description section, administrative requirements under the proposed Regulations would apply to any fossil-fuel fired electricity generation unit with capacity greater than or equal to 25MW that is connected to a NERC-regulated electricity system, while compliance requirements (i.e., meeting the 30 t/GWh emissions intensity limit or appropriate exception) would apply to any fossil-fuel fired electricity generation unit with capacity greater than or equal to 25MW that has net-exports to a NERC-regulated electricity system. In alignment with NextGrid modelling, the CBA estimates that 125 facilities would be subject to administrative requirements,[32] of which 124 would be expected to submit full-length annual reports. While certain facilities may be comprised of multiple electricity-generating units, the CBA assumes that the same "per event" administrative costs would be incurred for each facility, regardless of the number of units contained in each. Assumptions used to assess administrative costs are presented in Table 22.

Table 22. Administrative cost assumptions, by administrative activity (2022 constant dollars, undiscounted)

Administrative activity	Timing	Facility count (in 2024)	Occupational category	Hours spent	Hourly wage rate (including overhead)	Approximate cost per event
Familiarization with administrative requirements	2024	125	Natural and applied sciences occupations	12.0	$53.38	$641
Familiarization with administrative requirements	2024	125	Professional occupations in law and social, community and government services	8.0	$53.43	$427
Familiarization with administrative requirements	2024	125	Senior management occupations	4.0	$76.77	$307
Registration report – unit information and process flow diagram	2024	125	Natural and applied sciences and related occupations	4.0	$53.38	$214
Registration number assignment	2024	125	Office support occupations	0.5	$31.19	$16
Annual report – data retrieval and entry, sampling and analysis, calculations (CO_2 emissions, electricity generation, system net-exports), send report	2035 onward	124	Natural and applied sciences and related occupations	20.0	$53.38	$1,068

[32] The breakdown of 125 affected facilities is estimated as follows: 75 facilities from NAICS 2211 (Electric Power generation, transmission and distribution), 16 facilities from NAICS 2111 (Oil and Gas Extraction), 28 facilities from NAICS 3221 (Pulp, Paper and Paperboard Mills), two facilities from NAICS 3311 (Iron & Steel Mills and Ferro-alloy Manufacturing), one facility from NAICS 3251 (Basic chemical manufacturing), one facility from NAICS 3241 (Petroleum and Coal Product Manufacturing), one facility from NAICS 4881 (Support Activities for Air Transportation) and one facility from NAICS 6113 (Universities).

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Annual short report – calculate system net-exports, send report	2035 onward	1	Natural and applied sciences and related occupations	3.0	$53.38	$160
Annual report – calculation of net thermal energy produced	2035 onward	75	Natural and applied sciences and related occupations	4.0	$53.38	$214
Annual report – CCS captured emissions	2035 onward	19	Natural and applied sciences and related occupations	4.0	$53.38	$214
Annual report – CO_2 emissions associated with hydrogen or purchased steam	2035 onward	19	Natural and applied sciences and related occupations	1.0	$53.38	$53
Annual report – approval	2035 onward	124	Senior management occupations	2.0	$76.77	$154
Annual short report – approval	2035 onward	1	Senior management occupations	0.5	$76.77	$38
Annual report associated record making	2035 onward	125	Office support occupations	1.0	$31.19	$31

Under the policy scenario, NextGrid modelling estimates that the total capacity across all fossil-fuel fired electricity generation units would decrease by a total of 8.53% between 2024 and 2050, for an average decrease of 0.34% per year. This average annual decrease in capacity was used as a proxy for negative growth in the number of affected facilities over the analytical period. Using the inputs in Table 22 and the negative growth rate for affected facilities, the proposed Regulations would be expected to result in $2.0 million in incremental administrative costs to industry over the 27-year analytical period.

Government costs

The proposed Regulations would be expected to result in a total of $104 million in incremental government costs over the 27-year analytical period. Of this total, the central case modelling estimates that the government would spend $55 million in incremental federal funding under the modelled ITC associated with the incremental buildout of qualifying technologies denoted in Table 16. The government would also spend $48 million on program administration, comprised mostly of new salaries for the Department set to begin in 2024 when the Regulations are proposed to be registered. Costs associated with compliance promotion (i.e., costs related to developing, posting and distributing promotional materials) are expected to be minimal as the pool of impacted parties is limited and known.

Additionally, the Department would be expected to incur $1 million in incremental costs related to training, inspections, investigations and measures to deal with any alleged violations, as well as compliance and promotion activities. A one-time cost of $58,192 would also be required for the training of enforcement officers alongside a one-time cost of $84,195 for strategic intelligence assessment work (2022 dollars, undiscounted). The CBA assumes that these costs would occur in 2034, one year prior to the year that the emissions intensity limits begin applying to affected units. On-going (annual) costs of $32,912 would be required for administration, coordination and analysis to support enforcement activities, as well as $94,743 for enforcement broken down as follows: $15,259 for inspections (which includes Operations and Maintenance costs, transportation and sampling costs) and measures to deal with alleged violations (including warnings, environmental protection compliance orders and injunctions), $1,073 for investigations, $2,378 for prosecutions and $43,121 for ongoing intelligence (2022 dollars, undiscounted). The CBA assumes that these cost would begin in 2035, the year that the emissions intensity limits begin applying to affected units.

Cost-benefit statement

Number of years: 27 years (2024 to 2050)
Base year for costing: 2022

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Present value base year: 2023
Discount rate: 2%

Table 23. Summary of total incremental benefits (in millions of dollars unless otherwise stated)

Description	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)
Main benefit: climate change mitigation	-310	3,514	20,030	22,568	23,665	69,468	3,355
Co-benefit: climate change mitigation	635	1,489	5,436	5,346	5,163	18,069	873
Cost-savings to industry	67	946	5,013	4,619	4,334	14,979	723
Total monetized benefits	392	5,949	30,479	32,534	33,162	102,516	4,951
Main benefit: air pollution reductions (in kilotonnes)	11	34	183	122	118	467	17
Co-benefit: air pollution reductions (in kilotonnes)	4	6	26	52	52	140	5
Total quantified benefits (in kilotonnes)	15	40	209	174	169	607	22

Table 24. Summary of total incremental costs (in millions of dollars)

Description	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)
Capital costs for new electricity system capacity	4,534	25,398	17,246	4,543	1,946	53,667	2,592
Capital costs for new transmission lines	0	3,309	1,193	889	1,265	6,656	321
Fixed O&M costs	89	556	1,619	2,179	1,930	6,372	308
Residual value of capital on early retirements	0	1,263	0	0	0	1,263	61
International net import costs	41	1,357	-1,118	1,953	3,348	5,581	270
Administrative costs	0.2	0.1	0.6	0.6	0.5	2	0.1
Government costs	66	26	5	4	4	104	8
Total costs	4,731	31,910	18,945	9,568	8,492	73,647	3,557

Table 25. Cost-benefit statement for the proposed Regulations (millions of dollars)

Description	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)
Total monetized benefits*	392	5,949	30,479	32,534	33,162	102,516	4,951
Total monetized costs	4,731	31,910	18,945	9,568	8,492	73,647	3,557
Total net benefits	-4,339	-25,961	11,533	22,966	24,670	28,869	1,394

* Total benefits are likely underestimated as potential benefits to health and the environment that would accrue over time from air pollutant emission reductions have not been monetized in the CBA.

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As depicted in Table 25, the proposed Regulations are estimated to result in a total of $28.9 billion in monetized net benefits to society over the 27-year analytical period, or $1.4 billion in net benefits per year on an annualized basis.

Distributional analysis

Costs and cost-savings by province

The proposed Regulations are expected to result in a significant increase to domestic trade activity, greatly facilitated by the new provincial interties modelled by NextGrid to minimize the system-wide compliance costs. With the modelled interties from NextGrid in place, outputs from E3MC were used to estimate that domestic trade would increase by $43 billion in economic value over the 27-year analytical period (17% increase from the baseline scenario). As domestic trade constitutes a transfer between domestic parties, incremental domestic net import expenditure (import expenditure minus export revenue) from the proposed Regulations would be zero under the CBA, though significant and varying trade impacts would be felt province to province as shown in Table 26.

Table 26. Incremental domestic net import expenditure by province (millions of dollars)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)
NL	2	-31	-825	-770	-1,445	-3,068	-148
PE	0	5	61	171	118	355	17
NS	-10	-52	-448	-342	-690	-1,542	-74
NB	65	584	945	115	777	2,486	120
QC	-67	-540	337	-1,562	-2,139	-3,971	-192
ON	21	430	1,552	4,143	4,613	10,759	520
MB	-11	-408	-1,621	-1,673	-910	-4,623	-223
SK	-1	370	1,745	1,608	1,271	4,993	241
AB	73	917	3,475	4,342	7,538	16,344	789
BC	-72	-1,276	-5,222	-6,033	-9,134	-21,737	-1,050
YK	0	0	1	1	1	3	0
NT	0	0	0	0	0	0	0
NU	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0

To get a sense of the overall cost impact of the proposed Regulations to each province, the total cost-savings to provinces (avoided fuel usage, variable O&M and refurbishment) were subtracted from the total costs to provinces (capital costs for new electricity system capacity, capital costs for new transmission lines, fixed O&M, residual value of capital on early retirements, net international imports, net domestic imports and administrative costs) to obtain total net costs per province (Table 27). Positive values represent incremental net costs to provinces while negative values represent incremental net cost-savings to provinces. Normalized by provincial GDP, the provinces that would incur the greatest amount of net costs are New Brunswick, Saskatchewan and Alberta, while the provinces that would incur the greatest amount of net cost-savings are British Columbia and Newfoundland and Labrador.

Table 27. Incremental costs net of incremental cost-savings by province (in millions)

Province	2024-2030	2031-2035	2036-2040	2041-2045	2046-2050	27-year total	Annualized average (n=27)	Measure of relative cost by size of economy*
NL	2	28	-273	-627	-95	-964	-47	-1,190
PE	0	80	50	167	116	412	20	2,419

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NS	1,672	3,584	-313	-71	-1,695	3,177	153	3,089
NB	49.1	531	1,986	4,774	1,037	8,377	405	9,910
QC	4	176	-318	-579	-478	-1,194	-58	-118
ON	-60	5,579	9,896	481	3,457	19,353	935	968
MB	1	425	-286	-115	329	353	17	210
SK	346	2,416	3,687	1,155	3,600	11,204	541	5,292
AB	2,642	17,010	4,061	5,064	5,918	34,694	1,675	3,906
BC	-58.2	1,109	-4,562	-5,303	-8,034	-16,848	-814	-2,404
YK	0	0	1	1	1	3	0	31
NT	0	0	-2	-2	-2	-6	0	-51
NU	0	0	0	0	0	0	0	0
Total	4,598	30,938	13,928	4,944	4,154	58,561	2,828	N/A

* The values in this column were calculated by dividing the annualized average net costs to provinces (in dollars) by the projected contribution of each province to Canada's GDP (in millions of dollars) in 2023 (the discount base year in the CBA), as estimated by E3MC. The values in this column are only meaningful when compared against each other to denote relative positioning but have no real interpretation in isolation of each other.

Analysis of electricity rates

Generally speaking, residential electricity rates consist of a fixed rate portion and a variable rate portion. The fixed rate portion considers capital investment while the variable rate portion considers costs of generation. For the purpose of the CBA, it is assumed that the majority of costs incurred by electric utilities would be ultimately passed onto consumers through this pricing mechanism, in a manner that is specific to each province (given that electricity rates are a matter of provincial policy and are determined at the provincial level). In most cases, it is expected that investment into low and non-emitting generation technologies would increase the fixed rate portion of a household's electricity bill and decrease the variable rate portion. Where, according to provincially-determined rate-setting approaches, increases to fixed rates are applied equally across all consumers regardless of electricity usage, lower income households would pay a higher proportion of their household income to cover these costs relative to higher income households.

Under the proposed Regulations, while the variable costs of generation would decrease for several provinces, most provinces would first be expected to undertake significant capital investment to construct new low or non-emitting electricity generation capacity and new transmission lines. As would typically be the case in covering the costs of capital assets, such investment would be financed and paid back to lenders, thereby smoothing out the payments made on this capital over time.

E3MC was used to model the impact that the proposed Regulations may have on electricity rates to different segments of the economy over time. Such rates are generated by E3MC endogenously, using a complex formula that draws in results from other modelled variables such as purchases, sales, imports, exports, energy-related credits and taxes, and non-power costs. It should be noted that residential electricity rates generated by E3MC do not take province-specific rate-setting formulas into account, such as rate caps that may exist in some provinces. As such, the rate impacts modelled by E3MC may potentially overestimate the amplitude of rate increases or rate decreases. Ultimately, the cost of the electricity system in each province and the impact of that system on rates will be a reflection of decisions made at the provincial level in response to the proposed Regulations, which have the potential to vary from the impacts modelled by E3MC. It is also important to note that rate modelling in E3MC does not differentiate between changes to the fixed rate portion of an electricity bill versus the variable rate portion. Accordingly, rate increases modelled by E3MC represent average electricity bill increases across both dimensions, presented on a per kWh basis.

In the baseline scenario, the construction of new infrastructure (and operation of that modelled electricity system) would have been associated with average real residential electricity rate increases of 43% between 2025 and 2050 cumulatively. By contrast, in the regulatory scenario, the construction of new infrastructure (and operation of that modelled electricity system) would be associated with average real residential electricity rate increases of 45% between 2025 and 2050 cumulatively. The incremental

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change in real residential electricity rates (i.e., the change in rates that are attributable to the proposed Regulations) is only that captured by the difference in rates between the baseline and regulatory scenarios. Alternative impacts on rates following different methodology than under the central case modelling is explored in the sensitivity analysis. The sensitivity analysis explores the rate-impacting costs that follow from a modelling approach differing from that used under the central case modelling.

Under the proposed Regulations, E3MC modelling estimates that national average residential rates (in undiscounted 2022 constant dollars) would increase relative to the baseline scenario by 0.08 cents per kWh in 2035 (0.35% increase), 0.49 cents per kWh in 2040 (1.9% increase), 0.35 cents per kWh in 2045 (1.2% increase), and 0.26 cents per kwh in 2050 (0.89% increase). The majority of provinces and territories are expected to experience rate increases well below the national average, with some exhibiting rate reductions relative to the baseline. However, for provinces that currently rely more heavily on emitting technology to generate electricity, higher incremental rate increases are expected. For example, in 2040, E3MC modelling estimates that residential rates would increase relative to the baseline scenario by 3.9 cents per kWh in Nova Scotia (15% increase), 1.2 cents per kWh in Alberta (5% increase), 0.9 cents per kWh in Saskatchewan (3% increase), and 0.4 cents per kWh in New Brunswick (2% increase). E3MC modelling suggests that by 2050, incremental rate impacts will lessen at the national level from their high in 2040. For example, in 2050, E3MC modelling estimates that residential rates would increase relative to the baseline scenario by 2.6 cents per kWh in Nova Scotia (9% increase, 1.2 cents per kWh in Alberta (4% increase), and 1.1 cents per kWh in Saskatchewan (3% increase), while residential rates would decrease relative to the baseline scenario by 1.2 cents per kWh (4% decrease) in New Brunswick.

To put these modelled residential rate changes in context, the average single-detached home used 12,555 kWh of electricity in 2019 while the average high-rise apartment used 7,222 kWh of electricity.[33] Holding these usages constant and using them to form an illustrative range, national average annual electricity payments at the residential level could peak to an increase of $35 to $61 per household in 2040. However, relative to the baseline, national average annual electricity payments would only be $19 to $33 higher per household in 2050. It is important to note that such changes in national average annual electricity payments would be incremental to other increases expected in the baseline scenario. As is the case with incremental rates denoted above, provinces that currently rely more heavily on emitting technology to generate electricity are expected to experience greater increases to annual electricity payments relative to the baseline which would peak in 2040 but decrease somewhat for most provinces by 2050. For example, average annual incremental electricity payments at the residential level could be $279 to $485 higher in Nova Scotia in 2040 compared to the baseline, but only $185 to $322 higher in 2050. In 2040, while such payments would be expected to be $88 to $154 higher in Alberta relative to the baseline but only $86 to $149 higher in 2050. In 2040, such payments would be expected to be $32 to $55 higher in New Brunswick relative to the baseline (in line with the national average) but would be $88 to $153 lower than the baseline in 2050. In 2040, such payments would be expected be $64 to $111 higher relative to the baseline in Saskatchewan and $79 to $137 higher in 2050.

E3MC modelling estimates that incremental commercial and industrial rate changes in each province would follow a similar pattern and magnitude as residential rate changes (i.e., a 2.2% increase for commercial rates and 2.8% increase for industrial rates in 2040 and a 1.1% increase for commercial rates and 1.3% increase for industrial rates in 2050.

While the proposed Regulations are expected to increase electricity rates relative to the baseline scenario, these increases must be understood within the context of overall energy budgets, which are expected to be significantly impacted by the full suite of measures being put in place to support the clean electrification of the economy. For example, while households may see electricity rate increases, they would also experience cost-savings and greater price certainty as they transition to clean electricity from

[33] Statistics Canada (Table 25-10-0061-01): Household energy consumption, by type of dwelling, Canada and provinces

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increasingly costly fossil fuels to heat and cool their homes and to power their vehicles. As noted by the Canadian Climate Institute, "Increased household electricity use will correspond with decreased use of gasoline, natural gas, and other fossil fuels. While spending on electricity will likely increase, total energy spending will decline."[34] While assessing the impact of a full suite of measures on overall household energy budgets is out of scope for the CBA, such line of inquiry is explored in the Gender Based Analysis Plus section.

Analysis of household electricity demand

Household electricity demand and by extension, the rate at which households are expected to electrify, may be affected by the changes to residential electricity rates induced by the proposed Regulations. In response to higher electricity prices, consumers may shift their behaviour over time to reduce the amount of electricity that they use. For example, some households may respond by investing in more energy-efficient technologies and more energy-efficient homes. Alternatively, some households may respond by substituting from electricity to other sources of energy. Some households may also respond by decreasing the amount of electricity-dependent activities that they partake in (or reduce the hours spent on those activities). The particular behavioural shifts that a household would undertake depends on many factors such as price-elasticity of demand (how sensitive household electricity usage is to price), price and availability of substitute energy sources and individual preferences.

Outputs from E3MC were used to assess the potential impact of the proposed Regulations on household electricity demand and electrification. Table 28 depicts total residential electricity demand as a proportion of total residential energy demand in the baseline scenario versus in the regulatory scenario in select years.

Table 28. Total residential electricity demand as a proportion of total residential energy demand, baseline scenario versus regulatory scenario in select years

Province	Baseline scenario proportion (2025)	Regulatory scenario proportion (2025)	Baseline scenario proportion (2050)	Regulatory scenario proportion (2050)
NL	30.0%	30.0%	37.2%	37.2%
PE	12.1%	12.1%	33.6%	33.7%
NS	25.7%	25.7%	52.1%	51.0%
NB	34.9%	34.9%	50.3%	50.6%
QC	42.7%	42.7%	75.1%	75.0%
ON	16.9%	16.9%	29.5%	29.4%
MB	30.5%	30.5%	44.9%	44.8%
SK	10.9%	10.9%	14.9%	14.7%
AB	12.8%	12.8%	22.5%	22.0%
BC	23.8%	23.8%	44.5%	44.4%
YT	19.7%	19.7%	50.3%	50.3%
NT	7.7%	7.7%	11.4%	11.4%
NU	6.5%	6.5%	9.2%	9.2%
Average	21.1%	21.1%	36.6%	36.4%

As depicted in Table 28, electrification at the household level is expected to be significant in the baseline scenario, with households in several provinces expecting to double their proportion of electricity demand

[34] Source: Canadian Climate Institute - Electricity affordability and equity in Canada's energy transition, p.4.

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relative to total energy demand between 2025 and 2050. Such proportions are nearly identical between the baseline scenario and regulatory scenario, indicating that the proposed Regulations would not have a significant impact on the rate at which households are expected to electrify. Indeed, under the proposed Regulations, E3MC modelling estimates that national residential electricity demand would only decrease by around 1,000 GWh in 2050 (roughly 0.4% decrease from baseline electricity demand in that year). As such, substitution is not assessed to be a source of concern in the analysis and any potential consumer welfare impacts and GHG emissions that may be associated with these minor shifts in behaviour have not been assessed in the CBA.

Sensitivity analysis

The Department has conducted a two-part sensitivity analysis on the proposed Regulations using its NextGrid model, as well as a third part comparing key input costs used between NextGrid and E3MC. The first part assesses the impact that a higher demand for electricity would have on provincial electricity system mixes, emissions and total costs. The second part explores the effect of modifying various aspects of the proposed Regulations design including the level of the performance standard, the mass-based/duration flexibility provisions, the electricity generation capacity threshold, the inclusion of industrial units and the End of Prescribed Life. In all cases, the Regulatory scenario is compared to a baseline scenario, where the baseline scenario includes an increase in demand of 1.4 times over current demand by 2050 and all announced policies, excluding those announced in Budget 2023, for the electricity sector (the *Regulations Amending the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*, the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity* and carbon pollution pricing as it applies to electricity generation via the *Output-Based Pricing System Regulations*, or OBPS). The comparison is performed for the low demand scenario, modeled as 1.4 times (“1.4 X”) increase over current demand by 2050 and used in the CBA and for the high demand scenario, modeled as 2.5 times (“2.5 X”) increase over current demand by 2050. Since this sensitivity analysis on the proposed Regulations was conducted using the NextGrid model, these results cannot be combined with the results presented in the CBA, which uses the E3MC model.

Part 1

Changes in the mix of technologies deployed to meet demand

The Canadian Climate Institute recently reviewed a range of studies that estimate that achieving a net-zero economy will require an increase in overall electricity generation to become 1.6 to 2.1 times greater by 2050 compared to 2020 levels. Other studies had previously estimated that electricity demand would triple by 2050. Considering the difficulty of accurately predicting future growth in electricity demand, the Department chooses to assess sensitivities using a ‘bookend’ approach that assess outcomes for a low and high demand scenario consistent with this independent work. In this context, the 2.5 demand increase (“2.5 X”) represents a conservative, high bookend estimate that is intended to capture all of the electricity demand growth that would be seen under a net-zero economy. Conversely, the low demand scenario (“1.4 X”) assumes modest growth in electrification of other sectors, meaning that a greater share of the energy supply in decarbonization is coming from sources other than electricity, e.g., hydrogen. The actual load growth in Canada will depend on the extent to which Canadians ultimately come to rely on clean electricity for economy-wide de-carbonization by 2050. A heavy reliance on clean electricity, i.e., high demand growth, will result in a greater need for non-emitting electricity generating capacity by 2050 while a minor reliance on clean electricity, i.e., low demand growth, will likely result in relatively less deployment of non-emitting capacity. Not only would this have an impact on the capacity and generation mix in the electricity sector in 2050, it would also affect the resultant costs seen by generators and consumers and thus should be explored in this analysis of the impacts of the proposed Regulations.

The NextGrid model was used to project the mix of supply options that would be deployed by 2050 to supply the load growth scenario used in the cost-benefit analysis (i.e., 1.4 X current demand) and compared that to the mix that would arise under a 2.5 X scenario, which is similar to demand growth

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projections in recent literature[35]. This electricity system mix assessment was conducted for Canada as a whole, as well as for Alberta, Saskatchewan, Ontario, Nova Scotia and New Brunswick, as these are the provinces that currently have significant amounts of fossil fuel-based capacity that would become subject to the proposed Regulations. In comparing the electricity system mixes of the 2.5 X scenario to those of the 1.4X scenario, it would appear that under the proposed Regulations, the same technologies would, in general, be deployed regardless of the demand scenario, but more capacity would be deployed in the higher load scenario. This results in a cleaner electricity system on a per MWh basis, as the new deployments are largely low or non-emitting units. This is the expected result, as NextGrid optimises for lowest cost on a deployed technology basis (i.e., the optimal solution of deployed technologies scales in accordance with the scaled need for the same technologies). This same relation is seen for generation.

Changes in total emissions

In moving from a scenario in which the proposed Regulations regulate the emissions from meeting demand that is 1.4 X current to a scenario in which demand is 2.5 X current, it would be expected to see more emissions under the 2.5 X scenario. This is the expected outcome since, even though the proposed Regulations significantly reduce emissions from each unit, more units are required to meet more demand and hence there are more emissions at the jurisdictional level. This expected trend is generally seen in the sensitivity analysis, summarized in Table 29. Overall, the proposed Regulations are largely expected to be as effective under a 2.5 X scenario as it would be under a 1.4 X scenario. This is largely due to NextGrid projecting that increased demand would be predominately met with non-emitting generation whose variable nature is stabilized by a combination of increased inter-provincial electricity trade, energy storage, demand response and rarely used fossil fuel-fired generation. Differences are, however, seen at the provincial level. Notably, Quebec and Nova Scotia would see greater reductions under a 2.5 X scenario than under a 1.4 X scenario. Since this sensitivity analysis on the proposed Regulations was conducted using the NextGrid model, these results cannot be combined with the results presented in the CBA, which uses the E3MC model. The 1.4 X scenario was provided here to provide a reference point to the 2.5 X scenario results.

Table 29. Percent change in total emissions under the proposed Regulations for a 1.4 X and 2.5 X demand growth scenario

Jurisdiction	Percent change in emissions in the proposed Regulations – 1.4 X scenario relative to baseline scenario (2025-2050)	Percent change in emissions in the proposed Regulations – 2.5 X scenario relative to baseline scenario (2025-2050)
CAN	-28%	-32%
BC	-10%	-9%
AB	-26%	-27%
SK	-38%	-38%
MB	-55%	-38%
ON	-35%	-40%
QC	-39%	-70%
NB	-10%	-1%
NS	-1%	-71%
NL	-9%	-9%
PE	0%	-0%

[35] Bigger, Cleaner, Smarter: Pathways for aligning Canadian electricity systems with net-zero (climateinstitute.ca)

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Changes in total costs

The percent change in total costs under the proposed Regulations for a 1.4 X and 2.5 X demand growth scenario are summarized in Table 30. Given the lower costs of non-emitting generation, transmission and demand response relative to abated emitting generation, NextGrid projects that scenarios with higher demand would see disproportionately more of this demand met with non-emitting sources. As such, the proportional cost increases above baseline scenario for lower demand scenario are roughly constant with those of the higher demand scenario. Since this sensitivity analysis on the proposed Regulations was conducted using the NextGrid model, these results cannot be combined with the results presented in the CBA, which uses the E3MC model. The 1.4 X scenario was provided here to provide a reference point to the 2.5 X scenario results.

Table 30. Percent change in total costs under the proposed Regulations for a 1.4X and 2.5X demand growth scenario

Jurisdiction	Percent change in total costs in the proposed Regulations – 1.4X scenario relative to BAU	Percent change in total costs in the proposed Regulations – 2.5X scenario relative to BAU
CAN	5%	4%
BC	3%	1%
AB	4%	2%
SK	7%	4%
MB	8%	3%
ON	6%	4%
QC	4%	5%
NB	2%	0%
NS	4%	3%
NL	4%	13%
PE	7%	3%

Average electricity prices were calculated from NextGrid cost outputs by incorporating to them the costs for utility debt, distribution and transmission costs and other considerations for the final costs borne by consumers. These average prices account for volumetric electricity rates and fixed charges.

Based on NextGrid cost results for the 1.4 X scenario, calculated average electricity prices increase by 0.7 cents per kWh (4.0%) in 2035 and 0.7 cents per kWh (4.0%) in 2050, expressed as a simple-average at the national level and relative to the baseline. Similar small relative increases in average electricity prices are also seen in the 2.5 X scenario, with electricity prices increasing by 0.6 cents per kWh (4.0%) in 2035 and 0.3 cents per kWh (1.0%) in 2050. Similar to the E2020 results under a 1.4 X growth scenario, most provinces show small changes in residential electricity prices relative to the baseline although some provinces do show a more significant impact in electricity prices relative to the baseline (Nova Scotia, Prince Edward Island and Newfoundland and Labrador).

Since the above findings are on the basis of the differences between electricity prices in the regulatory scenario and the baseline scenario being arithmetically averaged over the ten provinces, the resulting national average treats the volume of electricity in each province as being equal. This is not the case in reality, as load varies significantly between provinces. If the national average electricity price is weighted by load, the resulting weighted average gives a closer sense of the impact of the proposed Regulations at the national level. The weighted average findings indicated a price increase of 0.3 cents per kWh (2.2%) in 2035 and 0.1 cents per kWh (0.8%) in 2050 for the 1.4X scenario. For the 2.5 X scenario, the price increases are approximately the same.

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Further analysis to understand these impacts is being conducted on data results from E2020 and NextGrid to ensure that robust conclusions are made that consider a range of cost outcomes.

Overall findings

Relative to lower demand scenarios, it can be expected that the proposed Regulations, under higher demand scenarios, would:

- help produce electricity systems with the same types of non-emitting technologies;
- be as effective in emissions reductions; and
- have similar total cost differences (in percentage) from the baseline scenario.

Part 2

The second part of the sensitivity analysis assesses the impacts on costs and emission reductions that would result if the following elements of the proposed Regulations were made more stringent or lenient:

1. **Performance standard:** Proposed value is 30 t/GWh; sensitivity analysis considers 0 t/GWh and 100 t/GWh;
2. **Units operating under the mass-based emission/duration flexibility:** It is proposed that the generation contribution of these units under the mass-based emission/duration flexibility be constrained to the yearly limits of 450 hours, (approximately equivalent to 5% utilization) and 150 kt of emissions. The sensitivity analysis considers: i) not allowing for any usage of this flexibility such that reliability must be ensured by non-fossil options and, ii) allowing utilization up to 10%;]
3. **Electricity Generation Capacity Threshold:** Proposed value is 25 MW; sensitivity analysis considers 2.5 MW and 50 MW. For clarity, only units with a capacity above the threshold would be subject to the proposed Regulations;
4. **Treatment of industrial units:** Proposed approach would only require those industrial units that have net-exports to a NERC-regulated electricity system in any given year to comply with the performance standard. Sensitivity analysis considers an approach in which all industrial generation is subject to the proposed Regulations and an approach in which no industrial generation is subject to the proposed Regulations; and
5. **Prescribed Life period:** Proposed value is 20 years; sensitivity analysis considers 0, 15, 25, 30, 35, 40 and 45 years.]

Sensitivity of each of the above parameters were assessed by running the NextGrid model with the proposed regulatory case having only one of the above parameters changed at a time. Impacts to costs and emissions are presented as percent change relative to the proposed regulatory case. More specifically:

The effect on the cost of the proposed Regulations is provided as:

Eq. 1

$$SA_C = \frac{\left(C^2_{Regulatory} - C_{BAU}\right) - \left(C^1_{Regulatory} - C_{BAU}\right)}{\left(C^1_{Regulatory} - C_{BAU}\right)}$$

where C_{BAU}, $C^1_{Regulatory}$ and $C^2_{Regulatory}$ represent the cumulative (2025 to 2050) discounted costs of the baseline scenario, Regulatory and Modified Regulatory scenario, respectively.

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The effect on emission reductions is provided as:

$$SA_E = \frac{\left(E^2_{Regulatory} - E_{BAU}\right) - \left(E^1_{Regulatory} - E_{BAU}\right)}{\left(E^1_{Regulatory} - E_{BAU}\right)} \quad \text{Eq. 2}$$

where E_{BAU}, $E^1_{Regulatory}$ and $E^2_{Regulatory}$ represent the cumulative (2025 to 2050) emissions of electricity generation the baseline scenario, Regulatory and Modified Regulatory scenario, respectively.

The following caveats are important in the consideration of the sensitivity findings:

- The costs are cumulative, discounted (using a 3% discount factor as opposed to the 2% used in the CBA) and annualized. The 3% discount factor was used to assess its impact on the resulting grid mixes (i.e., the observed combination of various generating sources that supply a NERC-regulated electricity system) and was found to have no discernable effect. While they have a large scope (they include the cost of new capital, fuel, fixed operations and maintenance (FOM), variable operations and maintenance (VOM), carbon, residual value of capital on early retirements and Variable Renewable Energy (VRE) integration costs), they exclude a number of items: cost for intra-provincial transmission, distribution, financing and any capital cost associated with assets already built out in 2022; and
- The findings assume that units that are required to comply with the emissions intensity limit under the proposed Regulations receive full exposure to the carbon price (170$/tonne CO_2e) starting in 2035.
- Since this sensitivity analysis on the proposed Regulations was conducted using the NextGrid model, these results cannot be combined with the results presented in the CBA, which uses the E3MC model.

Effects of varying the stringency of the performance standard

The proposed Regulations would require units to meet, with some exceptions, a performance standard of 30 t/GWh. To assess the sensitivity of the proposed Regulations' expected costs and emission reductions, this performance standard was assessed at 0 t/GWh (i.e., equivalent to a *de facto* ban on fossil fuel-fired generation at their End of Prescribed Life) not allowing for these units to provide back-up services for variable renewables or to install CCS and 100 t/GWh (which would avoid the proposed Regulations needing to provide time for the new CCS units to adapt to the stringent 30 t/GWh standard, i.e., 100 t/GWh on an annual average basis is easily obtainable by any CCS unit).

The more stringent approach of 0 t/GWh was found to increase costs by 20% and 18% for the 1.4X and 2.5X scenarios respectively while also increasing emission reductions by approximately 2% and 3% in the same respective demand scenarios. This more stringent approach thus does not seem to be a cost-effective approach for incremental reductions. The less stringent approach of a 100 t/GWh performance standard would not dramatically reduce expected costs (4% and 5% reduction for the 1.4X and 2.5X scenarios respectively) and potentially increase emissions by about 12% for each or the 1.4X and 2.5X scenarios). This sensitivity analysis suggests that the proposed performance standard of 30 t/GWh results in emissions reductions without dramatically increasing costs.

Effects of varying the duration of the mass-based emission/duration flexibility provisions

The proposed Regulations include exceptions to the 30 t/GWh performance standard for units that operate for less than 450 hr/yr and emit less than 150 kt/yr. For reference, 450 hours per year is equal to

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approximately 5% of the total hours in a year assuming operation at 100% capacity. This approach provides an important tool to regulatees to preserve the reliability of the electricity system by using units that meet these conditions to provide backup or peaking power and at potentially lower costs if the alternative means of producing this reliability power would be to build new capital projects. To assess the sensitivity of the proposed Regulations' expected costs and emission reductions, this mass-based emission/duration flexibility was assessed at 0% utilization (i.e., equivalent to not allowing for these units to provide back-up services for variable renewables) and at 10%; for the purpose of analysis, units using this flexibility were assumed to operate at 100% capacity. Additional assessment was conducted to determine the impacts of 8% utilization.

The more stringent approach of 0% utilization was found to increase costs by 12% and 33% for the 1.4X and 2.5X scenarios respectively while also increasing emission reductions by approximately 11% in both demand scenarios. This appears to indicate that seeking further emission reductions by constraining the use of emitting units to provide backup/peaking power to less than 450 hrs would not provide further reductions while costs would continue to increase with increasing electricity demand. This finding suggests that 450 hrs is likely the minimal value that should be considered. In this context, analyses indicated that the less stringent approach of a 10% utilization factor would not dramatically reduce expected costs (i.e., 3% and 1%, respectively, for the 1.4X and 2.5X scenarios) and would result in a proportionately higher loss of emission reductions (i.e., 6% and 15%, respectively, for the 1.4X and 2.5X scenarios). The assessment of 8% utilization for the 1.4X demand scenario indicated a reduction of costs of only 2% relative to 450 hours and a loss of emission reductions of ~4% This sensitivity analysis suggests that the proposed values of 450 hours and 150 kt provide the best balance of cost savings and emissions reductions.

The Department invites interested parties to provide specific, evidence-based comments and any data relevant to this important flexibility prior to the publication in the *Canada Gazette*, Part II. While the objective of the proposed Regulations is to reduce CO_2 emissions from the generation of electricity, it is also important that Canada's electricity supply remains reliable and affordable as this supports both the safety of Canadians and attaining Canada's goal of a net-zero GHG emission economy by 2050.

Effects of varying the value of the electricity generation capacity threshold value

Fossil fuel-fired electricity generating units that do not exceed a capacity of 25 MW would not be subject to the proposed Regulations. This approach avoids costs associated with units that have historically not been a major source of GHG emissions in Canada, while also providing flexibility for electricity system operators in locations where there may not be sufficient infrastructure. It would also reduce the cumulative cost to unit operators of complying with the regulations while also not sacrificing a significant amount of carbon emission reductions.

The effect on the cost of the proposed Regulations and on associated emission reductions were calculated for a more stringent threshold of 2.5 MW as well as for a less stringent threshold of 50 MW.

The more stringent threshold of 2.5 MW would have a negligible effect on both costs and emission reductions for both load scenarios. The small gains in emission reductions (on the order of 1%) does not warrant the very significant increase in the number of regulatees implementing the regulation, nor the loss of flexibility for operators in locations where there may not be sufficient electricity system infrastructure.

The less stringent threshold of 50 MW would decrease the cost of the proposed Regulations by 3% while also reducing the emission reductions by approximately 5% for both load scenarios. While the proportional decrease in costs to the loss of emission reductions is on par with the proposed approach, the greater generation capacity threshold of 50 MW might, result in a build out of units slightly less than 50 MW as a means to avoid being subject to the proposed Regulations. Although a similar avoidance pattern is theoretically possible with the proposed value of 25 MW, a fleet comprised of units each less than 25 MW would be expected to have a greater logistical inefficiency compared to a fleet comprised of units each less than 50 MW. This greater logistical inefficiency is deemed sufficient to discourage an

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appreciable build out of units slightly smaller than 25 MW. As such, the proposed approach of a 25 MW electricity generation capacity threshold is seen as the better approach.

Effects of varying the extent to which industrial generation is included within the scope of the proposed Regulations.

The Proposed Regulations would apply to industrial units that meet the applicability criteria including being connected to a NERC-regulated electricity system. However, only units that have net-exports in any given year would need to comply with the performance standard. This approach is expected to prevent a rush to generate electricity for sale to a NERC-regulated electricity system using industry-owned unabated fossil fuel-fired electricity generating units; the approach also relies on other instruments – that are tailored to specific industrial sectors – to reduce emissions associated with electricity generated solely for industrial activity.

The sensitivity of estimated costs and emission reductions to the proposed approach were analyzed for two alternative coverages of industrial units: a more stringent policy design in which all industrial units are fully covered regardless of whether or not they export to a NERC-regulated electricity system and a less stringent policy design in which industrial units are fully exempt from meeting the performance standard.

While the associated emission reductions of this more stringent approach are very high (105% and 80% higher for the 1.4X and 2.5X load scenarios, respectively), covering all industrial electricity generation units also significantly increases the cost of the proposed Regulations by 87% and 62% for the 1.4X and 2.5X load scenarios, respectively. This cost increase only considers the cost of generating electricity and industrial heat from cogeneration units and does not assess the secondary impacts that such costs could have on industrial activity specifically (e.g., potentially suppressing economic activity, reducing competitiveness, etc.) and on the Canadian economy more generally. As a result, this particular finding should not be considered as sufficient rationale for having all industrial generation subject to the performance standard in the proposed Regulations. Alternately, not making industrial generation subject to the proposed Regulations represents a scenario in which industrial generation can sell fossil-fired electricity on to the electricity system without limit. This approach would not significantly reduce the proposed Regulations' cost (2% for the 1.4x and 1% for the 2.5x scenarios) but would decrease the emission reductions by a noticeably higher amount: 35% and 26% for the 1.4X and 2.5X load scenarios, respectively. This analysis did not consider the potential of electricity moving from being generated by utility-owned units to being generated by industrial units firing on fossil-fuels unabated; by not considering this, the foregone emission reduction finding is likely biased, i.e., the forgone emission reductions are underestimated and would likely be higher than 35% and 26%. This finding indicates that the proposed approach of the proposed Regulations covering net-exporting industrial units is likely the better approach of the considered alternatives as it is less likely to produce broader economic impacts but is also one that results in low-cost emission reductions from the perspective of a whole economy.

Effects of varying the End of Prescribed Life

The proposed Regulations allow units commissioned before January 1st, 2025, to continue operating without being required to meet an emission intensity limit until the end of the unit's prescribed life, proposed to be set at 20 years, or January 1st, 2035, whichever comes later. This approach phases-in the activity needed to support a net-zero electricity system, thereby avoiding a steep capacity drop in 2035 while making sure that unabated fossil fuel-fired electricity generating units comply with the Regulations well in advance of 2050.

The effect on the cost of the proposed Regulations and on associated emission reductions were calculated for a suite of alternative numbers of years, from 0 years (i.e., existing units must meet the performance standard in 2035, just like new units) to 45 years (i.e., units are allowed to operate until the end of their technical life).

Setting the duration of the prescribe life to 0, 5, 10 or 15 years resulted in similar outcomes: The cost of the proposed Regulations in a 1.4X load scenario increases by about 8% but only increases emission

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reductions by 3%. For a 2.5X load scenario, the increase in cost is negligible and the emission reductions are only increased by 2%. Given the increased logistical difficulty that could be reasonably expected with an accelerated buildout of new capacity needed to ensure system reliability and the relatively small gain in emission reductions, decreasing the number of years that existing units can operate after commissioning does not seem to be advantageous.

Alternately, allowing existing units to operate for 35 to 45 years after commissioning dates does reduce the cost of the proposed Regulations, but at the detriment of significant losses in emission reductions. For the 1.4X load scenario, costs decrease by 14% to 77% for 35 to 45 years of operation, but emission reductions also decrease by 25% to 76%. For the 2.5X load scenario, the cost decrease associated with a prescribed life period of 35 to 45 years is 10% to 53%, but at the expense of 14% to 31% fewer emission reductions.

More moderate lengthening of the prescribed life period (i.e., to 25-30 years) is associated with moderate cost *increases* of the proposed Regulations. For the 1.4X load scenario, these increases range from 1% to 6% for 25 and 30 years, while these increases are from 4% to 2% for the same years in the 2.5X load scenarios. These increases in costs are accompanied by moderate losses in emission reductions: 4% and 12% for 25 and 30 years in the 1.4X scenario and by 3% and 7% for the same number of years in the 2.5X load scenario.

This indicates that the proposed length of 20 years of operation is the best option, balancing the phasing in of the regulation for reliability, managing costs and not sacrificing a substantial amount of emission reductions. However, if other considerations, such as logistical realities constraining the rate at which new capacity could be build-out, were to be demonstrated as a valid concern, longer prescribed life periods of no more than 30 years would not be expected to have significant impacts on the expected emission reductions of the proposed Regulations.

Part 3

The third part of the sensitivity analysis tests the total cost impact of using different input costs for key variables than those used in the central case modelling. In the CBA, total costs are sensitive with respect to one variable in particular: the marginal capital cost (per MW) of greenfield construction for electricity system technologies (marginal capital costs). This variable determines the scale of the cost impact associated with new capital buildout of predominantly abated emitting and non-emitting electricity generation technologies induced by the proposed Regulations, but also affects the scale of the impact associated with forgone refurbishment and the residual value of capital on early retirements.

The marginal capital costs used in the central case modelling were derived by E3MC. However, these are not the only estimates for capital costs that could be considered in the analysis. As part of the model development process for NextGrid, the Department commissioned an external contract to, among other tasks, compile a projection of marginal capital costs for key electricity system technologies in each province using information from reliable public sources such as the US Department of Energy, the OECD, the Bank of Canada and Canadian utilities. A sensitivity case was generated by mapping the technology types from the external contract to those from E3MC, revealing differences in marginal capital costs between the two approaches (Table 31).

Table 31. Percentage difference in marginal capital cost (per MW) in the sensitivity case relative to the central case, by technology type in select years (Canada average, based on 2022 constant dollars)

Technology type	2025	2030	2035	2040	2045	2050
OGCT	-9%	-9%	-9%	-9%	-9%	-9%
OGCC	-5%	-5%	-5%	-5%	-5%	-5%
Small OGCC*	-5%	-5%	-5%	-5%	-5%	-5%
NG CCS	-9%	-14%	-21%	-25%	-28%	-31%

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Nuclear	41%	41%	41%	41%	41%	41%
Base hydro	8%	8%	8%	8%	8%	7%
Peak hydro	8%	7%	7%	7%	7%	7%
Small hydro	-25%	-25%	8%	8%	8%	7%
Biomass	-1%	-12%	-21%	-41%	-41%	-41%
Biomass CCS*	-3%	-23%	-27%	-31%	-31%	-31%
Onshore wind	1%	2%	0%	1%	1%	2%
Offshore wind*	1%	2%	2%	2%	3%	4%
Solar PV	-11%	-10%	-10%	-10%	-9%	-6%
Storage	83%	113%	91%	94%	97%	101%

* The external contract did not determine marginal capital cost estimates for these technology types. To estimate values for the sensitivity case, percentage differences between two relevant central case costs were calculated and applied to the sensitivity case. For example, the value for small OGCC was generated by multiplying OGCC from the external contract by the percentage difference in cost between OGCC and small OGCC from E3MC. The same treatment was done for biomass CCS (percentage difference from biomass) and offshore wind (percentage difference from onshore wind).

The marginal capital costs from the sensitivity case were applied to the same electricity system mix modelled in the central case, generating the following results: relative to the central case over the 27-year analytical period (2024 to 2050), incremental capital costs for new electricity system capacity decreases by $929 million (1.7%), incremental refurbishment cost-savings increases by $115 million (208%) and residual value of capital on early retirements decreases by $98 million (7.8%).

While the sensitivity scenario generates similar total capital costs to the central scenario (i.e., $52.7 billion versus $53.7 billion), changes to the distribution of capital costs amongst provinces is noteworthy. Since natural gas units with CCS and biomass units are less costly in the sensitivity scenario relative to the central scenario, total incremental costs in Nova Scotia and Alberta decrease significantly. Similarly, since nuclear units and peak hydro units are more costly in the sensitivity scenario relative to the central scenario, total incremental costs in New Brunswick increase significantly. Costs to provinces under the sensitivity case are presented in Table 32 below.

Table 32. Annualized average (n=27) capital cost for new electricity system capacity by technology type and province in the sensitivity scenario (millions of dollars)

	NL	NS	NB	QC	ON	SK	AB	BC	Total
OGCT	0	37	-12	0	-2	-17	-42	0	-36
OGCC	0	0	-23	0	-4	-35	-85	0	-146
Small OGCC	0	-13	-25	0	-4	-39	-93	0	-175
NG CCS*	0	0	0	0	0	127	643	0	770
Nuclear	0	0	368	0	0	289	296	0	954
Base hydro	28	28	38	0	0	5	63	1	163
Peak hydro	0	0	0	14	481	0	0	104	599
Small hydro	23	0	0	-3	103	7	-98	11	42
Biomass	13	27	18	0	8	3	30	3	101
Biomass CCS	0	0	0	0	96	10	6	11	123
Onshore wind	19	73	0	2	-26	4	-28	5	49
Offshore wind	29	18	-0.04	0	0	0	0	0	47
Solar PV	0	2	0	-0.01	4	8	4	0.1	18
Storage	8	15	0	2	3	-2	9	3	39
Total	120	187	365	15	658	359	705	138	2,547
Percentage difference from central scenario	12%	-37%	32%	6%	4%	11%	-14%	11%	-2%

Small business lens

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The proposed Regulations would not impose any compliance or administrative requirements on small businesses as defined by the Treasury Board Secretariat of Canada (less than 100 employees or annual gross revenues below $5 million).

One-for-one rule

The one-for-one rule applies since there is an incremental increase in administrative burden on business. The proposal would repeal two existing regulatory titles, between 2035 and 2045, and introduce a new regulation which would result in a net decrease of one regulatory title. (Policy on Limiting Regulatory Burden on Business). These costs are described in the Administrative Costs subsection of the Benefits and Costs section. Relevant administrative cost inputs shown in Table 22 (i.e., those that would be incurred from 2024 to 2033) were transformed into 2012 constant dollars, then discounted to base year 2012 using a 7% discount rate. Under this methodology, the proposed Regulations would result in an annualized increase in administrative burden of $9,963 or $79.70 per facility. It is important to note that the calculation of burden in under the one-for-one rule does not include administrative costs associated with annual reporting that would begin in 2035 and only includes administrative costs associated with regulatory familiarization and submitting a registration report and registration assignment. The Red Tape Reduction Regulations specify the methodology required to estimate administrative burden costs which is limited to impacts incurred over the 10-year period that starts when the regulations would be registered. These costs are, however, estimated and reported as part of the CBA.

Regulatory cooperation and alignment

The proposed Regulations are a key pillar of the Emission Reductions Plan, Canada's climate plan to reach net-zero economy by 2050 (NZ2050) and would affect not only the electricity sector but other sectors as they decarbonize with clean electricity. The proposed Regulations would accelerate progress towards a net-zero electricity-generating sector, helping Canada become a net-zero GHG emissions economy by 2050. Canada has joined over 120 countries in committing to be net-zero emissions by 2050, including all other G7 nations. The proposed Regulations would not overlap with provincial or territorial regulations. As electricity is largely a domestic product and is only exported to the US, the only international alignment possible would be with the US. On March 24, 2023, President Biden and Prime Minister Trudeau issued a joint statement in which they referenced commitments by both countries to achieve net-zero electricity systems by 2035, with both countries also indicating their intention to propose regulations before this fall that will reduce greenhouse gas emissions from the North American electricity sector[36].

Modelling analysis to understand potential electricity trade dynamics between the US and Canada under the proposed Regulations will take place between pre-publication in the *Canada Gazette*, Part I and final publication in the *Canada Gazette*, Part II.

Strategic environmental assessment

In accordance with the *Cabinet Directive on the Environmental Assessment of Policy, Plan and Program Proposals*, a Strategic Environmental Assessment (SEA) was conducted for the proposed Regulations. The SEA concluded that the proposed Regulations are expected to result in positive environmental effects. Negative environmental effects related to the proposed Regulations could include the localized land-use impacts associated with new solar and wind power projects, or considerations around the storage/disposal of spent fuel from nuclear power plants, as the proposed Regulations are expected to

[36] Prime Minister Trudeau and President Biden Joint Statement | Prime Minister of Canada (pm.gc.ca)

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drive increased deployment of low carbon- sources of electricity generation. However, compared to the positive environmental effects from reducing the amount of fossil fuel-based electricity generation in Canada, the potential negative environmental effects would be limited. The proposal supports the 2022-2026 Federal Sustainable Development Strategy (FSDS) goals to “Increase Canadians’ Access to Clean Energy” “Foster Innovation and Green Infrastructure in Canada”,, “Take Action on Climate Change and Its Impacts”; “Improve Access to Affordable Housing, Clean Air, Transportation, Parks and Green Spaces, as well as Cultural Heritage in Canada”. The proposed Regulations are also expected to contribute to the related Sustainable Development Goals (SDGs) of the United Nations 2030 Agenda, in particular SDG 3 Good Health and Well-being; SDG 7 Affordable and Clean Energy; SDG 9 Industry, Innovation and Infrastructure; and SDG 13 Climate Action.

Without the proposed Regulations, under the current regulatory regime, E3MC estimates that the Canadian electricity generation sector would release 44 Mt of emissions in 2030, mostly due to electricity generation from natural gas, which is expected to continue into the 2040s. The proposed Regulations are one component of Canada’s Emissions Reduction Plan. Progress under the plan will be reviewed in progress reports produced in 2023, 2025 and 2027. Additional targets and plans will be developed for 2035 through to 2050.

Gender-based analysis plus

Using a gender-based analysis plus (GBA +), the Department has identified that, relative to the general Canadian population, the proposed Regulations may have disproportionate impacts, both positive and negative, on certain demographic groups. Furthermore, the impacts of climate change will have disproportionate impacts on these same demographics that can also be influenced by regional considerations, such as increased storms for coastal communities or more severe droughts and wildfires in more landlocked, central locations. These impacts may be experienced differently by individuals within these demographic groups and especially by those individuals who have intersecting and overlapping social identities.

The proposed Regulations would accelerate progress towards a net-zero electricity-generating sector, a key element of Canada achieving a net-zero GHG emissions economy by 2050. By virtue of their scope as a federal regulatory instrument, the proposed Regulations can help reduce Canada’s greenhouse gas emissions and contribute to global climate action. As some demographic groups of Canadians are more vulnerable to the adverse effects of climate change than the broader Canadian population, it is the expectation of the Department that these vulnerable demographic groups may feel more greatly any of the positive impacts from the successful mitigation of global climate change.[37,38] Accordingly, while the proposed Regulations would be beneficial to these demographic groups, the proposed Regulations would include measures to take into account the cost impacts on these same groups.

The proposed Regulations have been designed with several compliance flexibilities, including a mass-based emission/duration flexibility and an end-of-prescribed-life provision. These compliance flexibilities reduce the impacts of the proposed Regulations on costs, for example by lowering the residual value of capital on early retirement of assets. Provinces and Territories are responsible for approving changes to electricity rates and the actual impact of the proposed Regulations on rates would depend on provincial approaches to rate setting as well as sound investment decisions and good planning. However, higher rate impacts are more likely to occur in Alberta, Saskatchewan and Nova Scotia and to a lesser extent in New Brunswick, since their higher reliance on fossil fuel generation would require more capital turnover than in provinces that already have more non-emitting capacity, such as hydro. The Department has estimated electricity rate impacts by province (see analysis of electricity rates section), however, actual incremental impacts of the proposed Regulations on electricity rates would be influenced by provincial decisions on how to meet the regulatory standards. Furthermore, the Department expects that there

[37] The Intergovernmental Panel on Climate Change - IPCC Sixth Assessment Report: Summary for Policymakers.
[38] Government of Canada – Who is most impacted by climate change.

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would be distributional impacts among certain demographic groups and communities within fossil fuel reliant provinces, especially for those experiencing intersectionality.

Even small rate increases could disproportionately impact low-income households because they spend a greater proportion of their income on electricity and are more likely to experience energy poverty. For instance, a scoping paper commissioned by the Canadian Climate Institute found that, across all provinces, electricity expenditures were a larger burden for households with lower income, representing between two and ten percent of their income. In contrast, higher-income households spent between zero and two percent of their income on electricity.[39] Atlantic provinces may be particularly impacted as they typically have the highest rates of energy poverty in Canada.[40] Furthermore, low-income households may not have the ability to purchase technologies that would allow them to benefit from the electrification of end uses (e.g., heat pumps or electric vehicles). The Department is engaging with academics with expertise in the economics of electricity systems to understand the potential impacts of the proposed Regulations on electricity affordability (e.g., electricity rates), total electricity costs seen by households (with consideration for increased electrification) and changes to electricity expenditures as a share of income, however these potential impacts are expected to be offset by lower household expenditures on fossil fuels, due to electrification of home heating and transportation.[41]

The Department intends to factor the findings of this work into its rationale as it continues with engagement and further development of the proposed Regulations. As demonstrated in Budget 2023, the Government of Canada is pursuing a suite of complementary measures that support an affordable and reliable transition to clean electricity and electrification. The above-mentioned electricity affordability study could help inform potential future complementary measures.

Children, youth and future generations stand to face increasingly severe impacts from climate change if it progresses in their lifetimes and therefore, they stand to benefit more than today's adult generations from emissions reductions over the long-term. The proposed Regulations support intergenerational benefits by accelerating the build-out of clean electricity infrastructure, creating the foundation of the clean electricity grids of the future, which will be a key component of delivering long-term climate benefits to future generations through the emission reduction potential of electrification. While the proposed Regulations and the clean energy transition will have cost impacts on current generations, in general, future generations will benefit from those investments having been made. Moreover, increased access to clean energy can have long-term socioeconomic benefits for future generations by attracting industry and businesses that are increasingly seeking to use clean electricity and reduce operational emissions.

The current composition of the electricity sector labour market in Canada is represented more by certain groups. For example, in 2019, men held 67% of jobs in the electric power generation, transmission and distribution sector[42] and accounted for 63% of the workforce in the environmental and clean technology products sector.[43] The economic opportunities presented by a clean energy transition could result in a similar labour market composition. However, Canada is more likely to see a shortage of skilled workers than sustainable jobs[44] in the clean energy sector and there is an opportunity going forward for the inclusion of those that are currently underrepresented in the electric power generation, transmission and distribution industry, such as women (33%), Indigenous Peoples (3%) and visible minorities (12%).[45] Persons with disabilities[46] and LGBTQ2+ individuals[47] are also likely underrepresented in the electricity sector, but there is little public disaggregated data to quantify their representation. The federal

[39] Canadian Climate Institute - The Big Switch.
[40] Canadian Urban Sustainability Practitioners – Energy Poverty In Canada.
[41] Source: Canadian Climate Institute - Electricity affordability and equity in Canada's energy transition.
[42] Canadian Centre for Energy Information - Energy and employment.
[43] Statistics Canada - Gender characteristics of the environmental and clean technology products sector labour force, 2012 to 2019.
[44] Government of Canada – Sustainable Jobs Plan.
[45] Canadian Centre for Energy Information - Energy and employment.
[46] Statistics Canada – A demographic, employment and income profile of Canadians with disabilities aged 15 years and over, 2017.
[47] Statistics Canada – Labour and economic characteristics of lesbian, gay and bisexual people in Canada.

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government's interim Sustainable Jobs Plan, launched in February 2023, is a mechanism through which these impacts can be mitigated. An integral part of the Sustainable Jobs Plan is ensuring that the unique circumstances of marginalized and underrepresented groups are addressed to ensure their full and equal participation in the economy.

As the proposed Regulations accelerate the clean electricity transition, Canada will see an increase in low- and non-emitting forms of electricity generation (like renewables) and a decrease in emitting forms of electricity generation (like unabated natural gas generation). As this transition occurs, some workers that work with fossil-fuel based electricity generation may need to transition into new jobs. For some workers, this may require learning new skills, adapting career paths and trajectories, or relocating to places where new clean electricity jobs exist. This transition would predominantly impact men as the fossil fuel-based energy sector is male dominated[48]. Older workers may also face unique challenges transitioning to new employment, such as health issues, lack of workplace accommodations and ageism.[49] In 2019, 21% of electric power generation, transmission and distribution sector workers were aged 55 and older and 46% were aged 45 and older.[50]

There will be an ongoing role for some fossil fuel-based generation that will still require workers knowledgeable with these systems. In addition, those with experience in fossil fuel-fired electricity generation may possess some transferable skills and knowledge required to work with low-emitting and non-emitting forms of electricity generation. Students, younger workers and future generations may be better positioned to adapt their educational paths and careers to take advantage of a growing clean energy sector. While some workers will not be able to transition from jobs based in fossil-fuel generation, their number is anticipated to be low as the time provided between publication of the proposed Regulations and when the performance standard comes into effect in 2035, as well as the gradual retirement of existing fossil fuel-based generation, can allow time for the sector's labour force to gain new skills and take advantage of employment opportunities afforded by the clean energy transition.

Indigenous representatives have highlighted that energy affordability and continued access to reliable energy are concerns for Indigenous and remote communities. With this in mind, the proposed Regulations' compliance flexibilities have been designed to effectively exempt most Indigenous communities and northern, rural and remote communities not connected to a NERC-regulated electricity system, as they often lack affordable options to use non-emitting electricity generation.[51] At the same time, Indigenous representatives have expressed a desire for greater inclusion of Indigenous Peoples' in the clean energy transition in order to catalyze a transition away from diesel generation and promote local economic opportunities. As the number of Indigenous communities helping to provide clean electricity options in Canada continues to grow, the Government recognizes the substantial contribution that Indigenous communities can play in achieving a net-zero electricity system. The Government also recognizes the important role that the clean electricity transition can play in economic reconciliation. The Government of Canada will continue to engage with Indigenous partners and interested parties to build awareness of clean energy programs and funding opportunities for communities not connected to a NERC-regulated electricity system (i.e., 'off-grid communities). These efforts will support the Government's broader commitments to reconciliation and renewed relationships with Indigenous Peoples to achieve the goals enshrined in the United Nations Declaration on the Rights of Indigenous Peoples.[52]

Rationale

The proposed Regulations would contribute significantly to Canada's commitment to achieve net-zero emissions economy-wide by 2050. Achieving net-zero emissions on an economy-wide scale will require

[48] Canadian Centre for Energy Information - Energy and employment.

[49] Employment and Social Development Canada - Promoting the labour force participation of older Canadians - Canada.ca

[50] Canadian Centre for Energy Information - Energy and employment.

[51] Canada Energy Regulator – Clean Energy Projects in Remote Indigenous and Northern Communities.

[52] Government of Canada – Who is most impacted by climate change.

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broad electrification of sectors and end-uses that currently rely on fossil fuels, such as transportation, space and water heating and industrial activity. There is general agreement that the level of electrification needed to achieve the 2050 goal would require at least a doubling of Canada's electricity supply by 2050. In the baseline scenario, in which the proposed Regulations do not occur, provinces and territories are going to make significant investments in electricity generation and transmission over the next quarter century to meet this growing electricity demand. In this context, the Department estimates that investments of more than $400 billion[53] are needed as part of routine replacements of aging facilities and to expand generation to respond to increased demands coming from population and economic growth, the switch to electric vehicles, the adoption of electric building heating and the electrification of industrial processes such as steel and aluminum production.

Without further regulatory action, Canada is expected to experience an increase in emissions from the electricity sector.[54] Regulatory action has been determined to be the best approach to send unequivocal signals to transition the economy from fossil fuels to non-emitting sources.

Regulatory action will require commensurate investment. While these investments are expected to lead to increased electricity rates, research suggests that they will support a shift in energy use that will actually reduce overall household energy expenditures. The Climate Change Institute's *Clean Electricity, Affordable Energy* (June 2023) concludes that the average household spending on energy will decrease 12% by 2050 as people switch from fossil fuels to more efficient technologies like electric vehicles and heat pumps.

Even though household energy spending is expected to decrease, the Government of Canada also recognizes that electricity must remain affordable. While the incremental cost to ensure that expanded generation occurs in a way that leads toward a net-zero grid is expected to add only a small percentage to the overall cost of electricity, the Government of Canada has committed more than $50B to help decarbonize the sector. This funding could cover more than half of the incremental costs needed to ensure that this transformation leads to a net-zero grid and it provides an opportunity to provinces to greatly reduce the impact on rates, especially in Atlantic Canada and the Prairies.

Together with the suite of complementary federal measures, the proposed Regulations would accelerate Canada on the path to a net-zero electricity sector. While the provinces and territories are responsible for planning and operating their electricity systems, the federal government has jurisdiction to regulate GHG emissions under CEPA. Relative to the baseline scenario, the proposed Regulations would increase non-emitting and abated emitting generating sources and would significantly reduce unabated emitting generation by 2035, nearly completely by 2050.

While existing and planned carbon pricing systems implemented by provincial, territorial and federal governments could reduce emissions from fossil fuel-fired electricity generation, modelling results shows that the proposed Regulations are a required driver which would ensure that the sector's GHG emissions do not unduly increase under a scenario with a high growth in demand for electricity.

The Government of Canada's approach to addressing climate change is based on the principle of maximizing environmental performance improvements while minimizing adverse economic impacts. The

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[53] Developed through the NextGrid model, this figure represents the estimated cumulative cost of generation during the 27-year analytic period and includes the costs of operating existing and new generation as well as the capital cost of new generation built to meet increasing demand and to replace existing generation that retires due to end of mechanical life or because of the provisions in the already in force *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* and the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. The figure has been found to align with the comparative estimate made by the Departmental model E3MC. For clarity, the figure does not include the costs estimated for compliance with the proposed Regulations, i.e. this captures the baseline scenario costs.

[54] sources: IEA, Trottier

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proposed Regulations provide the electricity sector with adequate timelines to adjust their capital investments plans to meet the proposed CO_2 emissions standards by 2035.

A societal cost-benefit analysis was conducted for the proposed Regulations, which indicated that they would result in a net reduction of approximately 342 Mt CO_2e of GHG emissions between 2024 and 2050 under a central scenario in which electricity demand increases by 40%. The incremental benefit of achieving these reductions is estimated to be $102.5 billion while the incremental cost is estimated to be $73.6 billion over the same period. This results in a net benefit to society of approximately $28.9 billion.[55]

If provinces and utilities in Canada were to make a broad commitment to a net-zero electricity grid and take full advantage of federal funding support, the clean electrification agenda is expected to be achieved with minimal additional cost to ratepayers while helping reduce overall household and business energy costs.

Note: Key aspects of the proposed Regulations are presented in Annex I of this document, along with the rationale for those aspects

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Implementation and enforcement activities

Implementation

Once the proposed Regulations are published in the *Canada Gazette*, Part II, Departmental staff would lead the development and delivery of compliance promotion activities, as required. This may include posting information on the web, sending email/letters to regulatees informing them of publication, responding to information or clarification requests, sending reminder letters (as appropriate). The proposed Regulations would come into force on the date in which they are published in the *Canada Gazette*, Part II, while the performance standard comes into force starting on January 1, 2035.

In general, sectors affected by the proposed Regulations would be familiar with the proposed regulatory requirements due to extensive engagement efforts by the Department in 2022, including: multiple webinars (attended by over 400 people, including representatives of industry associations and industry sectors) and documents circulated by the Department that explain the development of the proposed Regulations, meetings between Departmental officials and industry and other representatives to inform the evolution of the proposed Regulations, request by the Department for written comments on the proposed regulatory frame and analysis of these comments by Departmental staff. Similar engagement activities are planned for 2023.

The Department anticipates publishing the *Clean Electricity Regulations* in the *Canada Gazette*, Part II in 2024. The proposed coming into force date would be January 1, 2025. Units that have a commissioning date before January 1, 2025 and meet the applicability criteria will need to register with the Department of the Environment by the end of the 2025 and units commissioned on or after January 1, 2025 will need to register within 60 days of commissioning. Following publication, non-coal units commissioned before January 1, 2025, will need to achieve a 30 t/GWh performance standard starting either January 1, 2035, or the January 1 of the year following the unit's end of prescribed life (20 years after commissioning), whichever is later. Coal units will need to achieve this performance standard starting on January 1, 2035

[55] Values in 2022$CAD, discounted at 2%.

regardless of their commissioning date. All units that are commissioned on or after January 1, 2025, regardless of the fuel combusted, will need to achieve the 30 t/GWh performance standard starting on January 1, 2035.

Enforcement Activities

As the proposed Regulations are made under CEPA, Enforcement Officers would, when verifying compliance with the proposed Regulations, apply the Compliance and Enforcement Policy for CEPA. This Policy sets out the range of possible responses to alleged violations, including warnings, directions, environmental protection compliance orders, tickets, ministerial orders, injunctions, criminal prosecution and environmental protection alternative measures (which are an alternative to a court prosecution after the laying of charges for a CEPA violation). In addition, the Policy explains when the Government of Canada will resort to civil suits by the Crown for cost recovery.

Contacts

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Unofficial Version

Annex 1 Summary of the proposed Regulations

Application	Rationale
The proposed Regulations would apply to electricity generating units that meet the three following criteria:	
Use any amount of fossil fuels to generate electricity	The need to address climate change requires the limitations of anthropogenic release of CO_2, the proposed Regulations would need to cover all potential sources of electricity generation emissions equally.
1. Has a capacity of 25 MW or greater	Avoids costs associated with units that are not expected to be a major source of GHG emissions in Canada, while providing flexibility for operators in locations where there may not be sufficient electricity system infrastructure. This is reflected in that units less than 25 MW currently account for approximately 2 percent of Canada's electricity sector emissions. In addition, since efficiency decreases with MW sizing, units less than 25 MW are too inefficient to be a viable option for broad deployment of baseload power.

2. Are connected to an electricity system that is subject to NERC standards	Avoids costs associated with units that: Generate mainly or solely for their own use, as these units are most often incorporated into larger industrial complexes that would be more appropriately regulated through instruments tailored to their industrial sector; and Are in remote or Northern locations, as these units are not expected to be a major source of GHG emissions in Canada and Northern locations do not have many options for low/non-emitting reliable electricity supplied at cost competitive locations.
Registration	**Rationale**
The proposed Regulations will require all units that meet the applicability criteria to register by the end of 2025 or, for units commissioned after January 1, 2025, within 60 days of commissioning.	The proposed Regulations require all units that may need to comply with the performance standard to register to demonstrate their awareness of their obligations and to provide the Department with the information necessary to conduct compliance promotion and enforcement activities prior to the performance standards applying.
Emission performance standards	**Rationale**
A unit means an assembly comprised of any equipment that is physically connected and that operates together to generate electricity and (a) must include at least a boiler or combustion engine; and (b) may include duct burners and other combustion devices, heat recovery systems, steam turbines, generators and emission control devices including CCS systems capturing emissions from the generation of electricity.	To maximize the emissions reductions achievable, the proposed Regulations would address power generation at the lowest level of production, which for the power sector is defined as 'a unit'. This approach aligns with that in the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* and the *Regulations Limiting Carbon Dioxide from Natural Gas-fired Generation of Electricity*.
Units, other than those combusting coal, commissioned before January 1st, 2025: Starting the latter of January 1, 2035 or 20 years after its commissioning, the proposed performance standard (30 t/GWh) would apply.	A phased in approach would allow existing units time to develop a compliance strategy and build/gain access to the needed infrastructure. By providing this flexibility, the reliability of the electricity system will be more easily maintained at current levels. This value aligns with the emissions intensity of natural gas generation with carbon capture and storage (CCS) achieving a 95% capture rate, which CCS experts and vendors have confirmed should be attainable by 2035.
Unit commissioned on or after January 1st, 2025: Starting on January 1st, 2035, the proposed performance standard would apply.	Providing new units 10 years to comply with the proposed Regulations offers flexibility. Operators will have sufficient time to undertake construction and obtain the materials needed for the provision of generating capacity sufficient to maintain reliability at current levels.

Unofficial Version

Unit that combusts coal or has increased its electricity generation capacity by at least 10 percent since its registration under the proposed Regulations: Starting on January 1st, 2035, the proposed performance standard would apply.	The overarching purpose of the phased in approach is to help bridge the transition that comes about from the application of the performance standard. Units that are covered by the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*, have already received such a phased in approach under those Regulations. Providing a second transition period would distort the emission reduction objectives of the proposed Regulations.
A unit that ceased burning coal and has been "significantly modified": Starting on the latter of January 1st 2035 or January 1st of the year after its life extension under the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*, the proposed performance standard would apply. For further information on the meaning of "significantly modified", refer to subsection 3(4) of the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity.*	These significantly modified units are included in the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. There is an alignment between the Regulations to ensure the reliability of the electricity system. Significantly modified units have no pathway to operate without a performance standard past 2039.
Only units that are *net* exporters in a given calendar year are subject to the performance standard in that year. Net exporters in this case applies to units that both generate power that is supplied to, and demand power from, a NERC-regulated electricity system. In this way, the proposed performance standard would **only** apply to those units that supply more power to a NERC-regulated electricity system than they demand.	The proposed Regulations impose limits upon the CO_2 associated with generation of electricity. The net export criterion is included here to distinguish between those facilities that are connected to an electricity system subject to NERC standards as a consumer versus those that are connected to an electricity system subject to NERC standards as a generator. The proposed Regulations require that the net exports are determined for each calendar year from which the prohibition would begin to apply to that unit. A unit with net exports in a calendar year will need to comply with the performance standard in that calendar year and in all subsequent years that it has net exports. These units would also be subject to quantification rules as of the first year with net exports once the prohibition would begin to apply to that unit.
Exceptions from meeting the general requirement to meet the 30 t/GWh performance standard	**Rationale**
Mass-based emission/duration flexibility limiting low usage/low emitting units to 450 hr/yr and 150 kt/yr. This exception can be used where all applicable conditions are met in that calendar year. If all of the conditions related to this exception are not met in a given calendar year, then the 30 t/GWh annual average performance standard must be complied with in that year.	Allows units, which are still capable of generating electricity, an emissions constrained role of adding value to the electricity system. For units which require this flexibility, the unit during periods of high demand or in which non-emitting sources are not available. In doing so, the flexibility reduces compliance costs and provides options for reserve power, thus helping to avoid reliability issues and upward pressures on affordability.

Unofficial Version

40 t/GWh available until the earlier of seven years after commissioning of a carbon capture and storage (CCS) system or December 31, 2039. This exception can be used where all applicable conditions are met in that calendar year. If all of the conditions related to this exception are not met in a given calendar year, then the 30 t/GWh annual average performance standard must be complied with in that year.	Allows units that have deployed CCS to meet the 30 t/GWh standard a limited time to adjust the CCS system and tailor its operation to the particularities of the unit. Allowing units that may not be able to meet the 30 t/GWh standard in their first seven years of operation to operate at the less stringent 40 t/GWh helps system operators provide reliable electricity. Furthermore to the above, tailoring is foreseen to be needed in the first generation of CCS applied to natural gas-fired generating units. The need for this exception will decrease over time and is anticipated to no longer be needed by 2040. Accordingly, limiting this flexibility supports the emission reduction objectives of the proposed Regulations.
Emergency circumstances The proposed Regulations contain a provision that allows emitting electricity generation in order to avoid a threat to the electricity supply or to restore it.	Allows for greater reliability of the electricity system, with benefits to improved quality of life and safety of Canadians. Additionally, this flexibility reduces costs, as it could allow units that would otherwise not be available in emergency circumstances to provide value in emergencies.
Quantification	**Rationale**
The measurement of the quantity of electricity generated during the course of a year, for use in determining compliance with the emission intensity performance standard, is to be measured on a gross basis.	This aligns with the approach taken under the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity* and recognizes quantification challenges for regulated units that have operations integrated with third parties not otherwise covered by the regulations.
For the amount of hydrogen fuel that a unit uses to produce electricity, the proposed Regulations would require emissions associated with that fuel's production to be included in the determination of the unit's emission intensity.	While there are no CO_2 emissions from the combustion of hydrogen fuel, the emissions associated with its production are at least equal to the emissions from the combustion of fossil fuels in an electricity generating unit. Accordingly, the proposed Regulations would require the hydrogen fuel production emissions to be included in the determination of the unit's emission intensity.
For the amount of steam produced outside a unit's facility and which the unit uses to produce electricity, the proposed Regulations would require emissions associated with that steam production to be included in the determination of the unit's emission intensity.	The emissions associated with the production of steam are at least equal to the emissions from the direct combustion of fossil fuels in an electricity generating unit. Accordingly, the proposed Regulations would require the steam production emissions to be included in the determination of the unit's emission intensity.
Reporting	**Rationale**
The proposed Regulations will require all units that meet the applicability criteria to submit a registration report that includes information such as: 6. Identification of the responsible person; 7. Location and name of the unit;	This is to provide the Department with the information necessary to conduct compliance promotion and enforcement activities prior to the application of the performance standard.

Unofficial Version

8. Process diagram of the unit, including the commissioning date of each boiler or combustion engine; 9. Commissioning date of the unit; and 10. Unit's electricity generating capacity	
The proposed Regulations will require all units that have net exports to submit an annual report that includes information such as the unit's: • Emission Intensity; • Generation; • Emissions; and • Hours of operation	This is to provide the Department with the information necessary to ensure compliance on an annual basis once the performance standard applies to that unit.
The proposed Regulations will require units that provide a declaration that they do not have net exports to annually submit information regarding their net exports.	Since the performance standard would have applied to these units if they had net exports, the Department requires that these units submit supporting documentation that shows that there are no net exports. All units must track their net exports as the performance standard will apply from the applicable year (as of 2035) for that unit if there are net exports in that year.

Unofficial Version

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 85

To provide the detailed calculations behind table entitled "depreciation provision, comparison of major accounts with intervenor-proposed lives" found in Exhibit N.M1.EGI-9, page 5.

Response:

Enbridge Gas notes the evidence reference should be Exhibit K16.2, page 5, rather than Exhibit N.M1-EGI-9, page 5.

The following response was provided by Concentric Energy Advisors:

Please see Attachment 1 for the detailed calculations for the Concentric-proposed lives and see Attachment 2 for the detailed calculations for the Intervenor-proposed lives.

Enbridge Gas Inc.

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1900	504.57	565	565	1.0000	0	0.00	0	121.5
1910	13,248.18	14,838	14,838	1.0000	0	0.00	0	111.5
1921	33,733.67	37,782	37,782	1.0000	0	0.00	0	100.5
1926	7,918.72	8,869	8,869	1.0000	0	0.00	0	95.5
1927	69,978.99	78,376	78,376	1.0000	0	0.00	0	94.5
1928	40,173.58	44,994	44,994	1.0000	0	0.00	0	93.5
1930	61,570.86	68,585	68,959	1.0000	0	0.50	0	91.5
1931	156,074.83	173,819	174,804	1.0000	0	0.51	0	90.5
1935	124.68	138	140	1.0000	0	1.10	0	86.5
1936	751,729.53	829,475	841,937	1.0000	0	1.28	0	85.5
1937	408,311.87	449,361	457,309	1.0000	0	1.49	0	84.5
1938	150,740.66	165,453	168,830	1.0000	0	1.70	0	83.5
1939	139,371.43	152,551	156,096	1.0000	0	1.92	0	82.5
1940	166,120.78	181,285	186,055	1.0000	0	2.14	0	81.5
1941	259,663.51	282,495	290,823	1.0000	0	2.37	0	80.5
1942	231,275.70	250,812	259,029	1.0000	0	2.60	0	79.5
1943	63,399.04	68,523	71,007	1.0000	0	2.85	0	78.5
1945	67,400.64	72,341	75,489	1.0000	0	3.33	0	76.5
1946	307,753.16	329,089	344,684	1.0000	0	3.58	0	75.5
1947	639,932.51	681,713	716,724	1.0000	0	3.83	0	74.5
1948	1,858.42	1,972	2,081	1.0000	0	4.08	0	73.5
1950	49,994.63	52,617	55,994	1.0000	0	4.59	0	71.5
1951	1,184,149.93	1,240,898	1,326,248	1.0000	0	4.85	0	70.5
1952	11,672.21	12,176	13,073	1.0000	0	5.12	0	69.5
1953	1,068,946.00	1,109,847	1,197,220	1.0000	0	5.39	0	68.5
1954	167,992.60	173,557	188,152	1.0000	0	5.68	0	67.5

Enbridge Gas Inc.

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1955	670,889.45	689,482	751,396	1.0000	0	5.97	0	66.5
1956	121,386.63	124,060	135,953	1.0000	0	6.28	0	65.5
1957	17,289,437.66	17,566,237	19,364,170	1.0000	0	6.60	0	64.5
1958	19,410,275.93	19,597,297	21,739,509	1.0000	0	6.94	0	63.5
1959	3,170,065.01	3,179,169	3,550,473	1.0000	0	7.30	0	62.5
1960	973,648.73	969,442	1,090,487	1.0000	0	7.68	0	61.5
1961	842,536.00	832,460	943,640	1.0000	0	8.08	0	60.5
1962	2,095,941.04	2,053,854	2,347,454	1.0000	0	8.51	0	59.5
1963	907,327.59	881,279	1,015,651	0.9995	556	8.96	62	58.5
1964	10,668,880.18	10,265,265	11,830,454	0.9901	118,692	9.43	12,584	57.5
1965	5,558,167.09	5,294,307	6,101,553	0.9801	123,595	9.93	12,442	56.5
1966	6,082,507.70	5,732,012	6,605,997	0.9697	206,412	10.46	19,732	55.5
1967	9,103,641.70	8,482,491	9,775,853	0.9588	420,225	11.01	38,168	54.5
1968	3,358,225.53	3,091,949	3,563,391	0.9474	197,821	11.58	17,083	53.5
1969	1,939,472.95	1,763,456	2,032,337	0.9356	139,872	12.17	11,494	52.5
1970	6,615,568.92	5,937,125	6,842,384	0.9235	567,053	12.77	44,401	51.5
1971	9,268,739.44	8,205,951	9,457,147	0.9110	923,841	13.39	69,019	50.5
1972	12,962,889.20	11,315,900	13,041,284	0.8983	1,477,152	14.01	105,442	49.5
1973	2,587,292.63	2,225,862	2,565,249	0.8852	332,519	14.64	22,712	48.5
1974	4,701,695.38	3,984,175	4,591,660	0.8720	674,239	15.28	44,123	47.5
1975	26,894,698.08	22,435,438	25,856,266	0.8584	4,265,796	15.93	267,760	46.5
1976	4,453,962.91	3,655,507	4,212,878	0.8445	775,561	16.59	46,746	45.5
1977	1,105,639.75	892,223	1,028,264	0.8304	210,053	17.26	12,169	44.5
1978	3,650,138.28	2,894,278	3,335,581	0.8159	752,574	17.94	41,941	43.5
1979	11,045,642.38	8,600,076	9,911,367	0.8012	2,459,753	18.64	131,991	42.5
1980	2,363,387.55	1,805,557	2,080,859	0.7861	566,136	19.34	29,273	41.5

Enbridge Gas Inc.

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1981	19,253,434.14	14,421,833	16,620,792	0.7708	4,943,054	20.06	246,456	40.5
1982	31,736,353.72	23,290,132	26,841,279	0.7551	8,703,437	20.78	418,762	39.5
1983	585,609.64	420,694	484,839	0.7392	171,044	21.52	7,947	38.5
1984	18,409,411.00	12,935,017	14,907,275	0.7230	5,711,265	22.28	256,394	37.5
1985	40,319,036.48	27,683,765	31,904,828	0.7065	13,252,493	23.04	575,239	36.5
1986	10,355,630.60	6,941,772	8,000,214	0.6898	3,598,092	23.81	151,095	35.5
1987	6,381,187.02	4,172,027	4,808,154	0.6728	2,338,776	24.60	95,070	34.5
1988	33,840,488.10	21,557,417	24,844,369	0.6555	13,056,977	25.40	514,089	33.5
1989	64,565,346.35	40,031,813	46,135,636	0.6380	26,177,552	26.21	998,847	32.5
1990	35,227,934.04	21,234,762	24,472,517	0.6203	14,982,769	27.03	554,330	31.5
1991	33,945,460.29	19,869,585	22,899,186	0.6023	15,119,730	27.86	542,716	30.5
1992	69,166,629.12	39,265,037	45,251,946	0.5841	32,214,679	28.70	1,122,423	29.5
1993	35,102,013.98	19,300,548	22,243,386	0.5658	17,070,870	29.55	577,634	28.5
1994	34,556,578.01	18,377,939	21,180,102	0.5472	17,523,265	30.41	576,155	27.5
1995	30,037,510.10	15,428,117	17,780,509	0.5285	15,861,503	31.28	507,001	26.5
1996	51,558,774.26	25,535,712	29,429,252	0.5096	28,316,575	32.17	880,352	25.5
1997	19,704,937.40	9,394,863	10,827,338	0.4906	11,242,192	33.05	340,125	24.5
1998	34,226,277.63	15,680,438	18,071,302	0.4714	20,262,129	33.95	596,829	23.5
1999	53,916,470.45	23,689,549	27,301,597	0.4521	33,084,850	34.85	949,236	22.5
2000	17,677,659.48	7,433,409	8,566,813	0.4327	11,232,166	35.77	314,050	21.5
2001	46,466,250.25	18,656,685	21,501,350	0.4132	30,540,850	36.68	832,537	20.5
2002	51,922,238.74	19,856,345	22,883,927	0.3935	35,268,980	37.61	937,773	19.5
2003	7,521,099.34	2,732,062	3,148,631	0.3738	5,275,000	38.54	136,870	18.5
2004	4,659,850.83	1,602,985	1,847,399	0.3540	3,371,634	39.48	85,408	17.5
2005	11,997,470.67	3,895,239	4,489,163	0.3341	8,948,004	40.42	221,381	16.5
2006	125,125,575.60	38,198,433	44,022,712	0.3141	96,117,932	41.37	2,323,615	15.5

Enbridge Gas Inc.

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2007	80,961,603.56	23,141,245	26,669,691	0.2941	64,007,305	42.32	1,512,567	14.5
2008	11,216,023.81	2,987,117	3,442,576	0.2740	9,119,371	43.27	210,743	13.5
2009	45,004,705.67	11,106,099	12,799,493	0.2539	37,605,777	44.23	850,203	12.5
2010	8,923,405.41	2,027,259	2,336,364	0.2338	7,657,850	45.19	169,444	11.5
2011	15,874,783.26	3,294,893	3,797,280	0.2136	13,982,477	46.16	302,916	10.5
2012	41,321,828.47	7,764,129	8,947,959	0.1933	37,332,489	47.13	792,157	9.5
2013	69,144,443.21	11,630,340	13,403,668	0.1731	64,038,108	48.10	1,331,406	8.5
2014	41,414,560.89	6,149,526	7,087,171	0.1528	39,297,138	49.07	800,829	7.5
2015	156,789,681.68	20,186,423	23,264,334	0.1325	152,340,109	50.04	3,044,100	6.5
2016	671,012,315.57	73,133,014	84,283,919	0.1121	667,249,874	51.02	13,078,350	5.5
2017	200,758,114.35	17,909,919	20,640,721	0.0918	204,208,367	52.00	3,927,461	4.5
2018	15,795,859.13	1,096,508	1,263,698	0.0714	16,427,665	52.97	310,132	3.5
2019	99,159,853.46	4,919,068	5,669,100	0.0510	105,389,936	53.94	1,953,723	2.5
2020	73,822,444.83	2,198,539	2,533,759	0.0306	80,147,379	54.91	1,459,588	1.5
2021	189,897,248.28	1,886,865	2,174,563	0.0102	210,510,355	55.86	3,768,579	0.5
TOTAL	2,783,251,797.20	799,994,108	919,330,147		2,197,911,866		49,201,672	

COMPOSITE ANNUAL ACCRUAL RATE	1.77%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	15.26
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	42.33

Enbridge Gas Inc.

Account #: 474.00 - Distribution - Regulators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 25
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1997	7,933,012.78	7,774,353	2,517,907	0.3174	5,415,106	0.50	5,415,106	24.5
1998	9,189,350.75	8,637,990	2,797,616	0.3044	6,391,735	1.50	4,261,157	23.5
1999	10,501,133.78	9,451,020	3,060,935	0.2915	7,440,199	2.50	2,976,079	22.5
2000	12,787,095.65	10,996,902	3,561,605	0.2785	9,225,490	3.50	2,635,854	21.5
2001	14,943,687.85	12,253,824	3,968,689	0.2656	10,974,999	4.50	2,438,889	20.5
2002	12,164,610.21	9,488,396	3,073,040	0.2526	9,091,570	5.50	1,653,013	19.5
2003	14,508,078.70	10,735,978	3,477,099	0.2397	11,030,980	6.50	1,697,074	18.5
2004	7,119,777.11	4,983,844	1,614,135	0.2267	5,505,642	7.50	734,086	17.5
2005	13,256,161.50	8,749,067	2,833,591	0.2138	10,422,571	8.50	1,226,185	16.5
2006	15,434,123.63	9,569,157	3,099,196	0.2008	12,334,927	9.50	1,298,413	15.5
2007	15,300,290.99	8,874,169	2,874,108	0.1878	12,426,183	10.50	1,183,446	14.5
2008	15,283,142.09	8,252,897	2,672,895	0.1749	12,610,248	11.50	1,096,543	13.5
2009	16,523,613.11	8,261,807	2,675,780	0.1619	13,847,833	12.50	1,107,827	12.5
2010	16,711,002.41	7,687,061	2,489,635	0.1490	14,221,367	13.50	1,053,435	11.5
2011	19,593,594.55	8,229,310	2,665,255	0.1360	16,928,339	14.50	1,167,472	10.5
2012	21,890,642.77	8,318,444	2,694,124	0.1231	19,196,519	15.50	1,238,485	9.5
2013	24,710,279.37	8,401,495	2,721,022	0.1101	21,989,258	16.50	1,332,682	8.5
2014	22,900,250.01	6,870,075	2,225,035	0.0972	20,675,215	17.50	1,181,441	7.5
2015	26,425,603.78	6,870,657	2,225,224	0.0842	24,200,380	18.50	1,308,129	6.5
2016	29,212,083.62	6,426,658	2,081,424	0.0713	27,130,659	19.50	1,391,316	5.5
2017	25,297,702.47	4,553,586	1,474,786	0.0583	23,822,916	20.50	1,162,093	4.5
2018	25,759,823.63	3,606,375	1,168,009	0.0453	24,591,814	21.50	1,143,805	3.5
2019	28,900,291.78	2,890,029	936,004	0.0324	27,964,288	22.50	1,242,857	2.5
2020	32,205,594.49	1,932,336	625,832	0.0194	31,579,762	23.50	1,343,820	1.5
2021	50,319,983.97	1,006,400	325,946	0.0065	49,994,038	24.50	2,040,573	0.5

Enbridge Gas Inc.

Account #: 474.00 - Distribution - Regulators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 25
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	488,870,931.00	184,821,829	59,858,893		429,012,038		43,329,779	

COMPOSITE ANNUAL ACCRUAL RATE	8.86%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.12
COMPOSITE AVERAGE AGE (YEARS)	9.45
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	15.55

Enbridge Gas Inc.

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -42%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1894	31.00	44	33	0.7528	11	0.00	11	127.5
1900	24.14	34	26	0.7529	8	0.00	8	121.5
1901	882.13	1,253	943	0.7529	309	0.00	309	120.5
1904	475.41	675	508	0.7529	167	0.00	167	117.5
1905	2,239.37	3,180	2,394	0.7529	786	0.00	786	116.5
1909	2,557.09	3,631	2,734	0.7529	897	0.00	897	112.5
1910	11,960.68	16,984	12,788	0.7529	4,196	0.00	4,196	111.5
1911	48.92	69	52	0.7529	17	0.00	17	110.5
1912	295.91	420	316	0.7529	104	0.00	104	109.5
1914	18,551.62	26,343	19,835	0.7529	6,509	0.00	6,509	107.5
1915	10.33	15	11	0.7526	4	0.00	4	106.5
1917	20.67	29	22	0.7529	7	0.00	7	104.5
1918	5,722.35	8,126	6,118	0.7529	2,008	0.00	2,008	103.5
1919	2,272.46	3,227	2,430	0.7529	797	0.00	797	102.5
1920	2,640.01	3,749	2,823	0.7529	926	0.00	926	101.5
1921	4,778.59	6,786	5,109	0.7529	1,677	0.00	1,677	100.5
1924	3,720.56	5,283	3,978	0.7529	1,305	0.00	1,305	97.5
1925	229,889.97	326,444	245,788	0.7529	80,656	0.00	80,656	96.5
1926	5,925.59	8,414	6,335	0.7529	2,079	0.00	2,079	95.5
1927	265,632.65	377,198	284,003	0.7529	93,196	0.00	93,196	94.5
1928	208,696.81	296,349	223,129	0.7529	73,220	0.00	73,220	93.5
1929	11,693.67	16,516	12,435	0.7489	4,170	0.50	4,170	92.5
1930	32,004.54	45,177	34,015	0.7485	11,432	0.55	11,432	91.5
1931	299,587.70	422,097	317,808	0.7471	107,607	0.71	107,607	90.5
1932	807.04	1,134	854	0.7454	292	0.91	292	89.5
1933	4,300.46	6,030	4,540	0.7435	1,566	1.12	1,397	88.5

Enbridge Gas Inc.

Account #: 475.21 - Distribution - Mains - Coated & Wrapped
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -42%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1934	4,519.92	6,322	4,760	0.7416	1,658	1.34	1,242	87.5
1935	37,493.72	52,300	39,378	0.7396	13,863	1.56	8,910	86.5
1936	49,203.14	68,438	51,529	0.7375	18,339	1.79	10,265	85.5
1937	98,402.01	136,464	102,747	0.7353	36,984	2.02	18,280	84.5
1938	49,373.63	68,260	51,395	0.7331	18,716	2.26	8,269	83.5
1939	118,259.02	162,977	122,709	0.7307	45,218	2.51	18,042	82.5
1940	46,288.16	63,588	47,877	0.7284	17,852	2.74	6,504	81.5
1941	92,337.02	126,428	95,191	0.7260	35,928	2.99	12,029	80.5
1942	3,659.02	4,993	3,759	0.7235	1,437	3.23	445	79.5
1943	10,116.06	13,756	10,357	0.7210	4,008	3.47	1,153	78.5
1944	10,235.69	13,869	10,442	0.7184	4,092	3.72	1,100	77.5
1945	3,439.76	4,644	3,497	0.7159	1,388	3.96	350	76.5
1946	76,563.83	102,993	77,546	0.7133	31,174	4.20	7,425	75.5
1947	4,547.68	6,095	4,589	0.7106	1,869	4.44	421	74.5
1948	19,057.29	25,442	19,156	0.7079	7,905	4.68	1,690	73.5
1949	5,248.90	6,980	5,255	0.7051	2,198	4.92	447	72.5
1950	33,682.36	44,609	33,588	0.7022	14,241	5.16	2,760	71.5
1951	187,806.18	247,704	186,503	0.6993	80,182	5.40	14,842	70.5
1952	96,014.69	126,092	94,938	0.6963	41,403	5.65	7,329	69.5
1953	340,239.03	444,820	334,916	0.6932	148,223	5.90	25,118	68.5
1954	294,801.17	383,611	288,831	0.6900	129,787	6.16	21,070	67.5
1955	438,970.93	568,413	427,973	0.6866	195,366	6.43	30,403	66.5
1956	1,541,821.69	1,986,222	1,495,479	0.6831	693,908	6.70	103,571	65.5
1957	10,729,456.30	13,747,496	10,350,851	0.6794	4,884,977	6.98	699,563	64.5
1958	30,571,577.15	38,948,297	29,325,195	0.6755	14,086,445	7.28	1,935,780	63.5
1959	36,689,474.62	46,462,310	34,982,693	0.6715	17,116,361	7.58	2,257,376	62.5

Enbridge Gas Inc.

Account #: 475.21 - Distribution - Mains - Coated & Wrapped
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -42%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1960	14,236,454.72	17,914,525	13,488,316	0.6672	6,727,450	7.90	851,567	61.5
1961	16,558,259.61	20,697,088	15,583,381	0.6628	7,929,348	8.23	963,417	60.5
1962	22,326,935.42	27,711,018	20,864,352	0.6581	10,839,896	8.57	1,264,259	59.5
1963	17,939,644.78	22,100,067	16,639,720	0.6532	8,834,575	8.93	989,120	58.5
1964	10,809,823.82	13,212,190	9,947,804	0.6481	5,402,146	9.30	580,650	57.5
1965	11,552,779.81	14,003,341	10,543,483	0.6427	5,861,465	9.69	604,905	56.5
1966	13,155,954.88	15,807,443	11,901,839	0.6371	6,779,617	10.09	671,870	55.5
1967	21,089,710.60	25,107,227	18,903,890	0.6312	11,043,499	10.51	1,051,112	54.5
1968	16,570,366.48	19,536,010	14,709,174	0.6251	8,820,746	10.94	806,472	53.5
1969	19,069,384.95	22,253,532	16,755,268	0.6188	10,323,258	11.38	906,901	52.5
1970	18,144,678.96	20,948,185	15,772,438	0.6122	9,993,006	11.84	843,792	51.5
1971	19,088,686.42	21,791,026	16,407,035	0.6053	10,698,899	12.32	868,620	50.5
1972	18,547,822.32	20,924,844	15,754,864	0.5982	10,583,043	12.81	826,465	49.5
1973	20,175,254.05	22,480,376	16,926,065	0.5908	11,722,795	13.31	880,876	48.5
1974	19,756,390.79	21,729,898	16,361,010	0.5832	11,693,065	13.82	845,840	47.5
1975	13,208,700.90	14,332,412	10,791,249	0.5753	7,965,107	14.35	554,943	46.5
1976	16,540,071.96	17,694,663	13,322,776	0.5672	10,164,126	14.89	682,424	45.5
1977	16,981,103.98	17,899,706	13,477,158	0.5589	10,636,009	15.45	688,543	44.5
1978	14,997,558.70	15,566,554	11,720,467	0.5503	9,576,067	16.01	598,050	43.5
1979	16,758,008.25	17,115,720	12,886,875	0.5415	10,909,497	16.59	657,646	42.5
1980	14,731,887.84	14,795,759	11,140,115	0.5325	9,779,166	17.18	569,364	41.5
1981	14,323,398.40	14,135,993	10,643,360	0.5233	9,695,865	17.77	545,557	40.5
1982	13,332,728.51	12,920,679	9,728,319	0.5138	9,204,156	18.38	500,804	39.5
1983	21,426,118.42	20,373,643	15,339,850	0.5042	15,085,238	18.99	794,203	38.5
1984	19,519,604.05	18,197,238	13,701,178	0.4943	14,016,659	19.62	714,421	37.5
1985	14,617,325.80	13,349,283	10,051,025	0.4842	10,705,577	20.25	528,584	36.5

Enbridge Gas Inc.

Account #: 475.21 - Distribution - Mains - Coated & Wrapped
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -42%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1986	14,706,593.66	13,145,826	9,897,838	0.4740	10,985,525	20.90	525,748	35.5
1987	31,059,637.62	27,150,048	20,441,984	0.4635	23,662,702	21.54	1,098,316	34.5
1988	19,343,553.30	16,519,694	12,438,111	0.4528	15,029,734	22.20	676,967	33.5
1989	39,248,495.27	32,715,021	24,631,998	0.4420	31,100,866	22.87	1,360,103	32.5
1990	40,677,356.96	33,058,174	24,890,367	0.4309	32,871,480	23.54	1,396,452	31.5
1991	74,523,446.21	58,985,208	44,411,510	0.4197	61,411,783	24.22	2,535,688	30.5
1992	27,487,891.82	21,164,531	15,935,330	0.4083	23,097,476	24.91	927,403	29.5
1993	26,003,959.82	19,452,902	14,646,600	0.3967	22,279,022	25.60	870,312	28.5
1994	43,932,383.15	31,888,357	24,009,581	0.3849	38,374,403	26.30	1,459,162	27.5
1995	39,499,790.13	27,779,222	20,915,705	0.3729	35,173,997	27.01	1,302,413	26.5
1996	36,452,530.54	24,801,162	18,673,446	0.3608	33,089,148	27.72	1,193,643	25.5
1997	26,797,860.90	17,609,822	13,258,897	0.3484	24,794,065	28.44	871,744	24.5
1998	35,597,604.06	22,553,901	16,981,424	0.3359	33,567,174	29.17	1,150,781	23.5
1999	43,830,609.47	26,723,719	20,120,989	0.3233	42,118,477	29.90	1,408,530	22.5
2000	34,427,768.62	20,157,783	15,177,324	0.3105	33,710,108	30.64	1,100,105	21.5
2001	42,096,541.71	23,616,187	17,781,247	0.2975	41,995,842	31.39	1,337,898	20.5
2002	44,496,198.90	23,858,452	17,963,654	0.2843	45,220,948	32.14	1,406,909	19.5
2003	20,542,914.89	10,499,191	7,905,116	0.2710	21,265,823	32.90	646,370	18.5
2004	25,714,395.59	12,489,262	9,403,493	0.2575	27,110,949	33.66	805,335	17.5
2005	40,386,777.13	18,578,492	13,988,234	0.2439	43,360,989	34.43	1,259,278	16.5
2006	54,401,891.70	23,613,180	17,778,983	0.2301	59,471,703	35.21	1,689,136	15.5
2007	86,472,776.23	35,265,312	26,552,178	0.2162	96,239,164	35.99	2,674,203	14.5
2008	50,243,100.21	19,159,116	14,425,401	0.2022	56,919,801	36.77	1,547,927	13.5
2009	46,101,813.60	16,346,913	12,308,019	0.1880	53,156,556	37.56	1,415,288	12.5
2010	28,606,114.10	9,371,083	7,055,734	0.1737	33,564,948	38.35	875,253	11.5
2011	56,729,296.73	17,038,819	12,828,974	0.1593	67,726,628	39.14	1,730,299	10.5

Enbridge Gas Inc.

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -42%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2012	29,117,111.47	7,945,441	5,982,331	0.1447	35,363,968	39.94	885,519	9.5
2013	78,911,056.58	19,347,181	14,567,000	0.1300	97,486,700	40.73	2,393,502	8.5
2014	147,219,903.94	31,983,882	24,081,504	0.1152	184,970,760	41.52	4,454,839	7.5
2015	68,235,901.61	12,903,946	9,715,719	0.1003	87,179,261	42.31	2,060,580	6.5
2016	458,760,681.23	73,743,330	55,523,288	0.0852	595,916,879	43.09	13,830,751	5.5
2017	109,428,743.25	14,461,680	10,888,578	0.0701	144,500,237	43.85	3,295,188	4.5
2018	196,754,404.11	20,332,924	15,309,192	0.0548	264,082,062	44.59	5,922,065	3.5
2019	141,819,538.75	10,534,949	7,932,039	0.0394	193,451,706	45.29	4,271,452	2.5
2020	178,851,789.99	8,038,300	6,052,247	0.0238	247,917,295	45.89	5,402,143	1.5
2021	363,811,882.15	5,530,162	4,163,804	0.0081	512,449,069	46.21	11,089,893	0.5
TOTAL	3,320,418,328.48	1,396,363,922	1,051,359,036		3,663,634,991		112,249,759	

COMPOSITE ANNUAL ACCRUAL RATE	3.38%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.32
COMPOSITE AVERAGE AGE (YEARS)	16.91
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	34.94

Enbridge Gas Inc.

Account #: 478.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S2.5
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1965	11,515.80	11,516	9,536	0.8280	1,980	0.00	1,980	56.5
1966	15,947.54	15,948	13,205	0.8280	2,742	0.00	2,742	55.5
1967	19,957.18	19,957	16,525	0.8280	3,432	0.00	3,432	54.5
1968	26,185.85	26,186	21,683	0.8280	4,503	0.00	4,503	53.5
1969	110,897.73	110,898	91,828	0.8280	19,070	0.00	19,070	52.5
1970	128,947.68	128,948	106,774	0.8280	22,174	0.00	22,174	51.5
1971	331,247.66	331,248	274,286	0.8280	56,962	0.00	56,962	50.5
1972	290,388.40	290,388	240,453	0.8280	49,936	0.00	49,936	49.5
1973	368,623.61	368,624	305,234	0.8280	63,389	0.00	63,389	48.5
1974	399,773.17	399,773	331,028	0.8280	68,746	0.00	68,746	47.5
1975	631,638.90	631,639	523,021	0.8280	108,618	0.00	108,618	46.5
1976	887,779.02	887,779	735,115	0.8280	152,664	0.00	152,664	45.5
1977	433,242.13	433,242	358,741	0.8280	74,501	0.00	74,501	44.5
1978	832,856.58	832,857	689,637	0.8280	143,219	0.00	143,219	43.5
1979	1,624,770.67	1,624,771	1,345,372	0.8280	279,398	0.00	279,398	42.5
1980	3,524,617.31	3,524,617	2,918,518	0.8280	606,099	0.00	606,099	41.5
1981	1,453,800.76	1,453,801	1,203,803	0.8280	249,998	0.00	249,998	40.5
1982	3,230,750.81	3,230,751	2,675,186	0.8280	555,565	0.00	555,565	39.5
1983	1,497,070.07	1,497,070	1,239,631	0.8280	257,439	0.00	257,439	38.5
1984	2,207,839.21	2,207,839	1,828,176	0.8280	379,664	0.00	379,664	37.5
1985	2,592,647.22	2,592,647	2,146,811	0.8280	445,836	0.00	445,836	36.5
1986	3,679,976.86	3,679,977	3,047,162	0.8280	632,815	0.00	632,815	35.5
1987	6,605,247.95	6,605,248	5,469,399	0.8280	1,135,849	0.00	1,135,849	34.5
1988	9,255,723.22	9,255,723	7,664,094	0.8280	1,591,629	0.00	1,591,629	33.5
1989	4,569,271.82	4,569,272	3,783,532	0.8280	785,739	0.00	785,739	32.5
1990	5,788,779.87	5,788,780	4,793,332	0.8280	995,448	0.00	995,448	31.5

Enbridge Gas Inc.

Account #: 478.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S2.5
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1991	7,174,653.94	7,174,654	5,940,889	0.8280	1,233,765	0.00	1,233,765	30.5
1992	7,640,147.03	7,640,147	6,326,335	0.8280	1,313,812	0.00	1,313,812	29.5
1993	8,874,564.78	8,721,555	7,221,782	0.8138	1,652,783	0.50	1,652,783	28.5
1994	11,920,608.64	11,667,779	9,661,369	0.8105	2,259,240	0.60	2,259,240	27.5
1995	21,968,294.96	21,373,191	17,697,822	0.8056	4,270,473	0.74	4,270,473	26.5
1996	13,715,285.30	13,249,725	10,971,281	0.7999	2,744,005	0.90	2,744,005	25.5
1997	13,768,080.78	13,198,207	10,928,622	0.7938	2,839,459	1.06	2,684,146	24.5
1998	16,411,566.76	15,598,578	12,916,221	0.7870	3,495,346	1.22	2,853,794	23.5
1999	12,007,631.53	11,306,252	9,362,011	0.7797	2,645,621	1.40	1,895,444	22.5
2000	16,649,433.65	15,515,652	12,847,555	0.7717	3,801,878	1.57	2,419,917	21.5
2001	15,518,144.90	14,293,469	11,835,541	0.7627	3,682,604	1.76	2,096,610	20.5
2002	15,851,999.51	14,407,900	11,930,294	0.7526	3,921,705	1.95	2,006,522	19.5
2003	18,457,550.88	16,521,784	13,680,671	0.7412	4,776,880	2.17	2,203,821	18.5
2004	10,414,273.80	9,157,941	7,583,126	0.7281	2,831,147	2.40	1,179,282	17.5
2005	23,798,080.35	20,496,859	16,972,186	0.7132	6,825,895	2.66	2,568,552	16.5
2006	27,435,896.11	23,059,565	19,094,205	0.6960	8,341,692	2.94	2,835,720	15.5
2007	26,144,359.34	21,347,445	17,676,504	0.6761	8,467,856	3.26	2,598,899	14.5
2008	30,673,221.79	24,198,674	20,037,430	0.6533	10,635,792	3.61	2,944,545	13.5
2009	31,630,017.27	23,949,487	19,831,094	0.6270	11,798,923	4.01	2,943,319	12.5
2010	34,775,468.83	25,067,694	20,757,013	0.5969	14,018,456	4.45	3,147,727	11.5
2011	40,398,219.52	27,451,830	22,731,168	0.5627	17,667,051	4.95	3,567,774	10.5
2012	41,599,497.81	26,329,807	21,802,090	0.5241	19,797,408	5.51	3,593,372	9.5
2013	37,834,256.29	21,982,770	18,202,576	0.4811	19,631,680	6.13	3,202,956	8.5
2014	43,308,908.70	22,693,215	18,790,853	0.4339	24,518,056	6.81	3,598,511	7.5
2015	60,792,567.30	28,099,837	23,267,743	0.3827	37,524,824	7.56	4,962,013	6.5
2016	47,739,140.49	18,927,180	15,672,431	0.3283	32,066,709	8.37	3,830,053	5.5

Enbridge Gas Inc.

Account #: 478.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S2.5
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2017	56,152,165.09	18,393,237	15,230,306	0.2712	40,921,859	9.24	4,429,772	4.5
2018	52,904,201.19	13,563,363	11,230,985	0.2123	41,673,216	10.15	4,104,996	3.5
2019	51,912,471.49	9,539,910	7,899,411	0.1522	44,013,060	11.10	3,963,703	2.5
2020	70,913,720.74	7,830,721	6,484,137	0.0914	64,429,583	12.08	5,331,918	1.5
2021	102,006,967.90	3,756,065	3,110,166	0.0305	98,896,802	13.08	7,561,514	0.5
TOTAL	1,020,910,893.69	567,033,992	469,525,898		551,384,996		104,686,374	

COMPOSITE ANNUAL ACCRUAL RATE	10.25%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.46
COMPOSITE AVERAGE AGE (YEARS)	11.32
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	6.37

Enbridge Gas Inc.

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 70
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1900	504.57	555	555	1.0000	0	0.00	0	121.5
1910	13,248.18	14,573	14,573	1.0000	0	0.00	0	111.5
1921	33,733.67	36,623	37,107	1.0000	0	1.33	0	100.5
1926	7,918.72	8,498	8,711	1.0000	0	2.39	0	95.5
1927	69,978.99	74,893	76,977	1.0000	0	2.63	0	94.5
1928	40,173.58	42,882	44,191	1.0000	0	2.85	0	93.5
1930	61,570.86	65,349	67,728	1.0000	0	3.33	0	91.5
1931	156,074.83	165,162	171,682	1.0000	0	3.57	0	90.5
1935	124.68	130	137	1.0000	0	4.56	0	86.5
1936	751,729.53	782,816	826,902	1.0000	0	4.82	0	85.5
1937	408,311.87	423,727	449,143	1.0000	0	5.07	0	84.5
1938	150,740.66	155,872	165,815	1.0000	0	5.33	0	83.5
1939	139,371.43	143,582	153,309	1.0000	0	5.59	0	82.5
1940	166,120.78	170,489	182,733	1.0000	0	5.85	0	81.5
1941	259,663.51	265,427	285,630	1.0000	0	6.13	0	80.5
1942	231,275.70	235,438	254,403	1.0000	0	6.40	0	79.5
1943	63,399.04	64,261	69,739	1.0000	0	6.69	0	78.5
1945	67,400.64	67,685	74,141	1.0000	0	7.30	0	76.5
1946	307,753.16	307,504	338,528	1.0000	0	7.62	0	75.5
1947	639,932.51	636,039	703,926	1.0000	0	7.95	0	74.5
1948	1,858.42	1,837	2,044	1.0000	0	8.30	0	73.5
1950	49,994.63	48,813	54,994	1.0000	0	9.05	0	71.5
1951	1,184,149.93	1,148,463	1,302,565	1.0000	0	9.46	0	70.5
1952	11,672.21	11,241	12,839	1.0000	0	9.89	0	69.5
1953	1,068,946.00	1,021,731	1,175,841	1.0000	0	10.33	0	68.5
1954	167,992.60	159,300	184,792	1.0000	0	10.80	0	67.5

Enbridge Gas Inc.

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 70
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1955	670,889.45	630,866	737,978	1.0000	0	11.29	0	66.5
1956	121,386.63	113,135	133,525	1.0000	0	11.81	0	65.5
1957	17,289,437.66	15,964,632	19,018,381	1.0000	0	12.34	0	64.5
1958	19,410,275.93	17,748,229	21,351,304	1.0000	0	12.89	0	63.5
1959	3,170,065.01	2,869,103	3,487,072	1.0000	0	13.46	0	62.5
1960	973,648.73	871,871	1,071,014	1.0000	0	14.05	0	61.5
1961	842,536.00	746,149	926,790	1.0000	0	14.65	0	60.5
1962	2,095,941.04	1,835,047	2,305,535	1.0000	0	15.26	0	59.5
1963	907,327.59	785,031	998,060	1.0000	0	15.87	0	58.5
1964	10,668,880.18	9,119,008	11,735,768	1.0000	0	16.50	0	57.5
1965	5,558,167.09	4,691,351	6,113,984	1.0000	0	17.13	0	56.5
1966	6,082,507.70	5,067,791	6,690,758	1.0000	0	17.77	0	55.5
1967	9,103,641.70	7,484,186	10,014,006	1.0000	0	18.42	0	54.5
1968	3,358,225.53	2,722,948	3,693,233	0.9998	816	19.08	43	53.5
1969	1,939,472.95	1,550,348	2,102,792	0.9856	30,628	19.74	1,551	52.5
1970	6,615,568.92	5,210,859	7,067,675	0.9712	209,450	20.42	10,256	51.5
1971	9,268,739.44	7,190,496	9,752,727	0.9566	442,886	21.11	20,984	50.5
1972	12,962,889.20	9,899,393	13,426,902	0.9416	832,276	21.80	38,177	49.5
1973	2,587,292.63	1,943,989	2,636,702	0.9265	209,320	22.50	9,301	48.5
1974	4,701,695.38	3,473,829	4,711,678	0.9110	460,187	23.22	19,820	47.5
1975	26,894,698.08	19,528,633	26,487,385	0.8953	3,096,783	23.94	129,338	46.5
1976	4,453,962.91	3,176,563	4,308,487	0.8794	590,873	24.68	23,945	45.5
1977	1,105,639.75	774,012	1,049,821	0.8632	166,383	25.42	6,545	44.5
1978	3,650,138.28	2,506,695	3,399,920	0.8468	615,232	26.18	23,503	43.5
1979	11,045,642.38	7,436,132	10,085,893	0.8301	2,064,314	26.94	76,619	42.5
1980	2,363,387.55	1,558,687	2,114,102	0.8132	485,624	27.72	17,520	41.5

Enbridge Gas Inc.

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 70
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1981	19,253,434.14	12,430,592	16,860,058	0.7961	4,318,719	28.50	151,521	40.5
1982	31,736,353.72	20,043,400	27,185,583	0.7787	7,724,406	29.30	263,650	39.5
1983	585,609.64	361,516	490,338	0.7612	153,833	30.10	5,110	38.5
1984	18,409,411.00	11,099,432	15,054,558	0.7434	5,195,794	30.92	168,057	37.5
1985	40,319,036.48	23,722,329	32,175,446	0.7255	12,175,494	31.74	383,602	36.5
1986	10,355,630.60	5,940,501	8,057,314	0.7073	3,333,879	32.57	102,351	35.5
1987	6,381,187.02	3,565,745	4,836,348	0.6890	2,182,958	33.41	65,330	34.5
1988	33,840,488.10	18,402,279	24,959,671	0.6705	12,264,866	34.26	357,946	33.5
1989	64,565,346.35	34,133,156	46,296,024	0.6519	24,725,857	35.12	703,965	32.5
1990	35,227,934.04	18,086,433	24,531,277	0.6331	14,219,450	35.99	395,098	31.5
1991	33,945,460.29	16,905,889	22,930,063	0.6141	14,409,943	36.87	390,881	30.5
1992	69,166,629.12	33,376,224	45,269,370	0.5950	30,813,922	37.75	816,324	29.5
1993	35,102,013.98	16,391,082	22,231,812	0.5758	16,380,404	38.64	423,956	28.5
1994	34,556,578.01	15,594,228	21,151,011	0.5564	16,861,225	39.53	426,504	27.5
1995	30,037,510.10	13,080,952	17,742,164	0.5370	15,299,097	40.44	378,348	26.5
1996	51,558,774.26	21,635,013	29,344,344	0.5174	27,370,308	41.35	661,975	25.5
1997	19,704,937.40	7,954,415	10,788,858	0.4977	10,886,573	42.26	257,601	24.5
1998	34,226,277.63	13,267,904	17,995,734	0.4780	19,653,172	43.18	455,109	23.5
1999	53,916,470.45	20,033,540	27,172,209	0.4582	32,135,909	44.11	728,541	22.5
2000	17,677,659.48	6,282,896	8,521,717	0.4382	10,923,708	45.04	242,523	21.5
2001	46,466,250.25	15,761,631	21,378,066	0.4183	29,734,810	45.98	646,707	20.5
2002	51,922,238.74	16,768,055	22,743,115	0.3982	34,371,348	46.92	732,554	19.5
2003	7,521,099.34	2,306,230	3,128,023	0.3781	5,145,187	47.87	107,492	18.5
2004	4,659,850.83	1,352,675	1,834,681	0.3579	3,291,155	48.81	67,421	17.5
2005	11,997,470.67	3,285,952	4,456,855	0.3377	8,740,363	49.77	175,621	16.5
2006	125,125,575.60	32,214,530	43,693,722	0.3175	93,944,411	50.72	1,852,052	15.5

Enbridge Gas Inc.

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 70
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2007	80,961,603.56	19,511,251	26,463,809	0.2972	62,593,955	51.68	1,211,084	14.5
2008	11,216,023.81	2,518,007	3,415,263	0.2768	8,922,364	52.65	169,476	13.5
2009	45,004,705.67	9,360,136	12,695,488	0.2564	36,809,688	53.61	686,598	12.5
2010	8,923,405.41	1,708,266	2,316,983	0.2360	7,498,763	54.58	137,392	11.5
2011	15,874,783.26	2,776,046	3,765,250	0.2156	13,697,011	55.55	246,577	10.5
2012	41,321,828.47	6,540,624	8,871,283	0.1952	36,582,728	56.52	647,251	9.5
2013	69,144,443.21	9,796,515	13,287,364	0.1747	62,771,523	57.49	1,091,813	8.5
2014	41,414,560.89	5,179,402	7,025,008	0.1542	38,531,009	58.47	659,020	7.5
2015	156,789,681.68	17,000,452	23,058,322	0.1337	149,410,328	59.44	2,513,542	6.5
2016	671,012,315.57	61,586,443	83,531,902	0.1132	654,581,646	60.42	10,834,305	5.5
2017	200,758,114.35	15,081,313	20,455,326	0.0926	200,378,600	61.39	3,263,868	4.5
2018	15,795,859.13	923,286	1,252,287	0.0721	16,123,159	62.37	258,521	3.5
2019	99,159,853.46	4,141,779	5,617,643	0.0515	103,458,195	63.34	1,633,411	2.5
2020	73,822,444.83	1,851,078	2,510,684	0.0309	78,694,006	64.30	1,223,794	1.5
2021	189,897,248.28	1,588,602	2,154,678	0.0103	206,732,295	65.25	3,168,528	0.5
TOTAL	2,783,251,797.20	684,511,674	919,330,147		2,142,246,830		39,083,025	

COMPOSITE ANNUAL ACCRUAL RATE	1.40%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	15.26
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	51.48

Enbridge Gas Inc.

Account #: 474.00 - Distribution - Regulators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L1
ASL: 50
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1997	7,933,012.78	3,979,446	2,120,453	0.2673	5,812,560	24.34	238,800	24.5
1998	9,189,350.75	4,496,552	2,395,993	0.2607	6,793,357	24.53	276,990	23.5
1999	10,501,133.78	5,003,652	2,666,202	0.2539	7,834,931	24.72	316,939	22.5
2000	12,787,095.65	5,921,617	3,155,341	0.2468	9,631,754	24.93	386,399	21.5
2001	14,943,687.85	6,711,371	3,576,163	0.2393	11,367,525	25.15	452,065	20.5
2002	12,164,610.21	5,285,659	2,816,470	0.2315	9,348,140	25.38	368,356	19.5
2003	14,508,078.70	6,082,772	3,241,213	0.2234	11,266,866	25.62	439,691	18.5
2004	7,119,777.11	2,871,811	1,530,248	0.2149	5,589,529	25.89	215,929	17.5
2005	13,256,161.50	5,126,895	2,731,872	0.2061	10,524,289	26.16	402,265	16.5
2006	15,434,123.63	5,702,048	3,038,344	0.1969	12,395,780	26.45	468,563	15.5
2007	15,300,290.99	5,376,599	2,864,928	0.1872	12,435,363	26.76	464,649	14.5
2008	15,283,142.09	5,083,517	2,708,758	0.1772	12,574,384	27.09	464,230	13.5
2009	16,523,613.11	5,173,268	2,756,582	0.1668	13,767,031	27.43	501,980	12.5
2010	16,711,002.41	4,892,593	2,607,025	0.1560	14,103,978	27.78	507,719	11.5
2011	19,593,594.55	5,323,462	2,836,613	0.1448	16,756,981	28.15	595,350	10.5
2012	21,890,642.77	5,468,902	2,914,112	0.1331	18,976,531	28.53	665,234	9.5
2013	24,710,279.37	5,613,555	2,991,190	0.1211	21,719,089	28.92	751,107	8.5
2014	22,900,250.01	4,665,461	2,485,997	0.1086	20,414,253	29.31	696,412	7.5
2015	26,425,603.78	4,743,100	2,527,367	0.0956	23,898,237	29.71	804,277	6.5
2016	29,212,083.62	4,511,712	2,404,071	0.0823	26,808,012	30.11	890,307	5.5
2017	25,297,702.47	3,253,106	1,733,422	0.0685	23,564,281	30.49	772,748	4.5
2018	25,759,823.63	2,625,091	1,398,783	0.0543	24,361,041	30.85	789,783	3.5
2019	28,900,291.78	2,148,497	1,144,829	0.0396	27,755,462	31.13	891,642	2.5
2020	32,205,594.49	1,474,781	785,839	0.0244	31,419,756	31.26	1,005,229	1.5
2021	50,319,983.97	801,493	427,077	0.0085	49,892,907	30.89	1,615,106	0.5

Enbridge Gas Inc.

Account #: 474.00 - Distribution - Regulators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L1
ASL: 50
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	488,870,931.00	112,336,957	59,858,893		429,012,038		14,981,768	

COMPOSITE ANNUAL ACCRUAL RATE	3.06%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.12
COMPOSITE AVERAGE AGE (YEARS)	9.45
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	28.61

Enbridge Gas Inc.

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 70
Net Salvage: -33%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1894	31.00	41	40	0.9728	1	0.00	1	127.5
1900	24.14	32	31	0.9730	1	0.00	1	121.5
1901	882.13	1,173	1,141	0.9729	32	0.00	32	120.5
1904	475.41	630	613	0.9688	20	0.50	20	117.5
1905	2,239.37	2,963	2,883	0.9679	96	0.61	96	116.5
1909	2,557.09	3,359	3,268	0.9609	133	1.41	94	112.5
1910	11,960.68	15,677	15,253	0.9588	655	1.64	399	111.5
1911	48.92	64	62	0.9568	3	1.87	2	110.5
1912	295.91	386	376	0.9546	18	2.10	9	109.5
1914	18,551.62	24,098	23,446	0.9502	1,228	2.57	478	107.5
1915	10.33	13	13	0.9477	1	2.81	0	106.5
1917	20.67	27	26	0.9432	2	3.29	0	104.5
1918	5,722.35	7,359	7,160	0.9408	451	3.54	127	103.5
1919	2,272.46	2,915	2,836	0.9383	186	3.78	49	102.5
1920	2,640.01	3,377	3,286	0.9358	225	4.03	56	101.5
1921	4,778.59	6,097	5,932	0.9333	424	4.27	99	100.5
1924	3,720.56	4,707	4,580	0.9255	369	5.00	74	97.5
1925	229,889.97	290,007	282,158	0.9228	23,596	5.24	4,503	96.5
1926	5,925.59	7,454	7,252	0.9202	629	5.48	115	95.5
1927	265,632.65	333,124	324,108	0.9174	29,184	5.72	5,101	94.5
1928	208,696.81	260,942	253,880	0.9147	23,687	5.96	3,976	93.5
1929	11,693.67	14,576	14,181	0.9118	1,371	6.20	221	92.5
1930	32,004.54	39,768	38,692	0.9090	3,875	6.44	602	91.5
1931	299,587.70	371,060	361,017	0.9060	37,435	6.68	5,603	90.5
1932	807.04	996	969	0.9030	104	6.93	15	89.5
1933	4,300.46	5,291	5,148	0.9000	572	7.17	80	88.5

Enbridge Gas Inc.

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 70
Net Salvage: -33%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1934	4,519.92	5,541	5,391	0.8968	620	7.43	84	87.5
1935	37,493.72	45,800	44,560	0.8936	5,306	7.68	691	86.5
1936	49,203.14	59,878	58,257	0.8902	7,183	7.94	904	85.5
1937	98,402.01	119,285	116,057	0.8868	14,818	8.21	1,805	84.5
1938	49,373.63	59,610	57,997	0.8832	7,670	8.48	904	83.5
1939	118,259.02	142,177	138,329	0.8795	18,955	8.77	2,162	82.5
1940	46,288.16	55,407	53,907	0.8756	7,656	9.06	845	81.5
1941	92,337.02	110,023	107,045	0.8716	15,763	9.35	1,685	80.5
1942	3,659.02	4,339	4,222	0.8675	645	9.66	67	79.5
1943	10,116.06	11,937	11,614	0.8632	1,840	9.98	184	78.5
1944	10,235.69	12,016	11,691	0.8588	1,923	10.30	187	77.5
1945	3,439.76	4,016	3,907	0.8541	667	10.64	63	76.5
1946	76,563.83	88,891	86,485	0.8493	15,345	10.99	1,396	75.5
1947	4,547.68	5,249	5,107	0.8443	942	11.35	83	74.5
1948	19,057.29	21,861	21,269	0.8392	4,077	11.72	348	73.5
1949	5,248.90	5,983	5,821	0.8338	1,160	12.10	96	72.5
1950	33,682.36	38,135	37,103	0.8282	7,695	12.49	616	71.5
1951	187,806.18	211,155	205,440	0.8225	44,342	12.90	3,438	70.5
1952	96,014.69	107,171	104,270	0.8165	23,429	13.31	1,760	69.5
1953	340,239.03	376,915	366,714	0.8104	85,804	13.74	6,245	68.5
1954	294,801.17	324,019	315,250	0.8040	76,836	14.18	5,419	67.5
1955	438,970.93	478,554	465,601	0.7975	118,230	14.63	8,082	66.5
1956	1,541,821.69	1,666,601	1,621,493	0.7907	429,130	15.09	28,433	65.5
1957	10,729,456.30	11,495,898	11,184,752	0.7838	3,085,425	15.57	198,220	64.5
1958	30,571,577.15	32,456,328	31,577,873	0.7766	9,082,325	16.05	565,853	63.5
1959	36,689,474.62	38,582,629	37,538,360	0.7693	11,258,641	16.55	680,434	62.5

Enbridge Gas Inc.

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 70
Net Salvage: -33%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1960	14,236,454.72	14,824,162	14,422,935	0.7617	4,511,550	17.05	264,573	61.5
1961	16,558,259.61	17,066,313	16,604,400	0.7540	5,418,085	17.57	308,378	60.5
1962	22,326,935.42	22,769,905	22,153,620	0.7460	7,541,204	18.10	416,745	59.5
1963	17,939,644.78	18,095,783	17,606,007	0.7379	6,253,720	18.63	335,614	58.5
1964	10,809,823.82	10,780,964	10,489,169	0.7296	3,887,897	19.18	202,709	57.5
1965	11,552,779.81	11,387,433	11,079,224	0.7211	4,285,973	19.74	217,164	56.5
1966	13,155,954.88	12,811,237	12,464,491	0.7124	5,032,929	20.30	247,913	55.5
1967	21,089,710.60	20,281,200	19,732,273	0.7035	8,317,042	20.87	398,428	54.5
1968	16,570,366.48	15,729,773	15,304,034	0.6944	6,734,553	21.46	313,855	53.5
1969	19,069,384.95	17,861,517	17,378,081	0.6852	7,984,201	22.05	362,147	52.5
1970	18,144,678.96	16,761,706	16,308,037	0.6758	7,824,386	22.65	345,503	51.5
1971	19,088,686.42	17,383,865	16,913,358	0.6662	8,474,595	23.25	364,470	50.5
1972	18,547,822.32	16,643,995	16,193,513	0.6564	8,475,091	23.87	355,118	49.5
1973	20,175,254.05	17,830,874	17,348,267	0.6465	9,484,821	24.49	387,356	48.5
1974	19,756,390.79	17,188,508	16,723,288	0.6364	9,552,712	25.11	380,388	47.5
1975	13,208,700.90	11,306,829	11,000,801	0.6262	6,566,771	25.75	255,043	46.5
1976	16,540,071.96	13,923,519	13,546,668	0.6158	8,451,627	26.39	320,293	45.5
1977	16,981,103.98	14,049,408	13,669,150	0.6052	8,915,718	27.04	329,782	44.5
1978	14,997,558.70	12,188,677	11,858,781	0.5945	8,087,972	27.69	292,114	43.5
1979	16,758,008.25	13,370,286	13,008,409	0.5836	9,279,742	28.35	327,361	42.5
1980	14,731,887.84	11,531,727	11,219,611	0.5726	8,373,799	29.01	288,631	41.5
1981	14,323,398.40	10,993,185	10,695,645	0.5614	8,354,474	29.68	281,461	40.5
1982	13,332,728.51	10,026,324	9,754,954	0.5501	7,977,575	30.36	262,770	39.5
1983	21,426,118.42	15,776,729	15,349,719	0.5386	13,147,018	31.04	423,542	38.5
1984	19,519,604.05	14,062,524	13,681,911	0.5270	12,279,162	31.73	386,996	37.5
1985	14,617,325.80	10,295,663	10,017,003	0.5153	9,424,041	32.42	290,668	36.5

Enbridge Gas Inc.

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 70
Net Salvage: -33%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1986	14,706,593.66	10,118,944	9,845,067	0.5033	9,714,702	33.12	293,310	35.5
1987	31,059,637.62	20,858,730	20,294,173	0.4913	21,015,146	33.82	621,291	34.5
1988	19,343,553.30	12,667,983	12,325,114	0.4791	13,401,812	34.53	388,077	33.5
1989	39,248,495.27	25,041,205	24,363,445	0.4667	27,837,053	35.25	789,726	32.5
1990	40,677,356.96	25,259,143	24,575,485	0.4543	29,525,400	35.97	820,885	31.5
1991	74,523,446.21	44,989,910	43,772,223	0.4416	55,343,960	36.69	1,508,264	30.5
1992	27,487,891.82	16,115,249	15,679,077	0.4289	20,879,819	37.42	557,935	29.5
1993	26,003,959.82	14,786,915	14,386,695	0.4160	20,198,571	38.16	529,327	28.5
1994	43,932,383.15	24,199,517	23,544,539	0.4030	34,885,531	38.90	896,820	27.5
1995	39,499,790.13	21,047,605	20,477,936	0.3898	32,056,785	39.64	808,619	26.5
1996	36,452,530.54	18,761,669	18,253,870	0.3765	30,227,996	40.39	748,323	25.5
1997	26,797,860.90	13,301,382	12,941,370	0.3631	22,699,785	41.15	551,663	24.5
1998	35,597,604.06	17,010,135	16,549,743	0.3496	30,795,070	41.91	734,821	23.5
1999	43,830,609.47	20,125,859	19,581,137	0.3359	38,713,573	42.67	907,248	22.5
2000	34,427,768.62	15,159,614	14,749,307	0.3221	31,039,625	43.44	714,544	21.5
2001	42,096,541.71	17,736,489	17,256,437	0.3082	38,731,963	44.21	876,053	20.5
2002	44,496,198.90	17,895,055	17,410,711	0.2942	41,769,233	44.99	928,461	19.5
2003	20,542,914.89	7,864,875	7,652,006	0.2801	19,670,071	45.77	429,779	18.5
2004	25,714,395.59	9,344,326	9,091,415	0.2658	25,108,731	46.55	539,395	17.5
2005	40,386,777.13	13,883,592	13,507,822	0.2515	40,206,591	47.34	849,368	16.5
2006	54,401,891.70	17,626,548	17,149,472	0.2370	55,205,044	48.13	1,147,110	15.5
2007	86,472,776.23	26,296,339	25,584,609	0.2225	89,424,184	48.92	1,828,090	14.5
2008	50,243,100.21	14,271,842	13,885,563	0.2078	52,937,760	49.71	1,064,944	13.5
2009	46,101,813.60	12,165,221	11,835,960	0.1930	49,479,452	50.50	979,737	12.5
2010	28,606,114.10	6,967,341	6,778,765	0.1782	31,267,367	51.30	609,532	11.5
2011	56,729,296.73	12,657,483	12,314,898	0.1632	63,135,066	52.09	1,212,051	10.5

Enbridge Gas Inc.

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 70
Net Salvage: -33%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2012	29,117,111.47	5,897,457	5,737,838	0.1482	32,987,920	52.88	623,803	9.5
2013	78,911,056.58	14,349,446	13,961,067	0.1330	90,990,638	53.67	1,695,407	8.5
2014	147,219,903.94	23,704,488	23,062,908	0.1178	172,739,564	54.45	3,172,381	7.5
2015	68,235,901.61	9,557,075	9,298,405	0.1025	81,455,344	55.22	1,475,003	6.5
2016	458,760,681.23	54,581,952	53,104,650	0.0870	557,047,056	55.98	9,950,380	5.5
2017	109,428,743.25	10,697,700	10,408,158	0.0715	135,132,070	56.72	2,382,371	4.5
2018	196,754,404.11	15,033,220	14,626,335	0.0559	247,057,023	57.42	4,302,291	3.5
2019	141,819,538.75	7,784,806	7,574,104	0.0402	181,045,883	58.07	3,117,551	2.5
2020	178,851,789.99	5,937,185	5,776,491	0.0243	232,096,390	58.60	3,960,866	1.5
2021	363,811,882.15	4,082,523	3,972,026	0.0082	479,897,777	58.76	8,166,926	0.5
TOTAL	3,320,418,328.48	1,080,606,484	1,051,359,036		3,364,797,341		70,073,136	

COMPOSITE ANNUAL ACCRUAL RATE	2.11%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.32
COMPOSITE AVERAGE AGE (YEARS)	16.91
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	47.37

Enbridge Gas Inc.

Account #: 478.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L1.5
ASL: 25
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1965	11,515.80	10,821	11,516	1.0000	0	3.63	0	56.5
1966	15,947.54	14,933	15,948	1.0000	0	3.77	0	55.5
1967	19,957.18	18,619	19,957	1.0000	0	3.92	0	54.5
1968	26,185.85	24,335	26,186	1.0000	0	4.07	0	53.5
1969	110,897.73	102,644	110,898	1.0000	0	4.22	0	52.5
1970	128,947.68	118,846	128,948	1.0000	0	4.38	0	51.5
1971	331,247.66	303,948	331,248	1.0000	0	4.54	0	50.5
1972	290,388.40	265,222	290,388	1.0000	0	4.70	0	49.5
1973	368,623.61	335,046	368,624	1.0000	0	4.86	0	48.5
1974	399,773.17	361,517	399,773	1.0000	0	5.03	0	47.5
1975	631,638.90	568,164	631,639	1.0000	0	5.19	0	46.5
1976	887,779.02	794,129	887,779	1.0000	0	5.37	0	45.5
1977	433,242.13	385,286	433,242	1.0000	0	5.54	0	44.5
1978	832,856.58	736,154	832,857	1.0000	0	5.71	0	43.5
1979	1,624,770.67	1,426,951	1,624,771	1.0000	0	5.89	0	42.5
1980	3,524,617.31	3,074,767	3,516,640	0.9977	7,978	6.07	1,314	41.5
1981	1,453,800.76	1,259,349	1,440,329	0.9907	13,472	6.25	2,154	40.5
1982	3,230,750.81	2,778,020	3,177,248	0.9834	53,503	6.44	8,311	39.5
1983	1,497,070.07	1,277,340	1,460,906	0.9758	36,164	6.62	5,460	38.5
1984	2,207,839.21	1,868,524	2,137,048	0.9679	70,791	6.81	10,395	37.5
1985	2,592,647.22	2,175,542	2,488,188	0.9597	104,459	7.00	14,927	36.5
1986	3,679,976.86	3,060,416	3,500,226	0.9512	179,751	7.19	25,011	35.5
1987	6,605,247.95	5,441,850	6,223,895	0.9423	381,353	7.38	51,704	34.5
1988	9,255,723.22	7,550,803	8,635,924	0.9330	619,800	7.56	81,940	33.5
1989	4,569,271.82	3,689,354	4,219,548	0.9235	349,723	7.75	45,118	32.5
1990	5,788,779.87	4,623,784	5,288,265	0.9135	500,515	7.94	63,064	31.5

Enbridge Gas Inc.

Account #: 478.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L1.5
ASL: 25
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1991	7,174,653.94	5,666,248	6,480,541	0.9033	694,113	8.12	85,489	30.5
1992	7,640,147.03	5,962,733	6,819,634	0.8926	820,513	8.30	98,871	29.5
1993	8,874,564.78	6,840,530	7,823,578	0.8816	1,050,986	8.47	124,018	28.5
1994	11,920,608.64	9,069,238	10,372,573	0.8701	1,548,036	8.65	179,046	27.5
1995	21,968,294.96	16,485,571	18,854,703	0.8583	3,113,592	8.81	353,284	26.5
1996	13,715,285.30	10,144,267	11,602,094	0.8459	2,113,192	8.98	235,411	25.5
1997	13,768,080.78	10,028,328	11,469,493	0.8330	2,298,588	9.14	251,583	24.5
1998	16,411,566.76	11,760,407	13,450,488	0.8196	2,961,079	9.29	318,598	23.5
1999	12,007,631.53	8,455,871	9,671,059	0.8054	2,336,572	9.45	247,236	22.5
2000	16,649,433.65	11,506,909	13,160,560	0.7905	3,488,874	9.61	363,102	21.5
2001	15,518,144.90	10,509,617	12,019,947	0.7746	3,498,198	9.77	358,069	20.5
2002	15,851,999.51	10,500,946	12,010,031	0.7576	3,841,969	9.94	386,641	19.5
2003	18,457,550.88	11,933,889	13,648,901	0.7395	4,808,650	10.11	475,491	18.5
2004	10,414,273.80	6,555,375	7,497,444	0.7199	2,916,830	10.30	283,144	17.5
2005	23,798,080.35	14,540,172	16,629,731	0.6988	7,168,349	10.51	682,326	16.5
2006	27,435,896.11	16,213,362	18,543,375	0.6759	8,892,522	10.73	828,849	15.5
2007	26,144,359.34	14,881,824	17,020,481	0.6510	9,123,878	10.97	831,441	14.5
2008	30,673,221.79	16,734,231	19,139,097	0.6240	11,534,125	11.24	1,025,712	13.5
2009	31,630,017.27	16,440,305	18,802,931	0.5945	12,827,086	11.55	1,110,653	12.5
2010	34,775,468.83	17,097,647	19,554,739	0.5623	15,220,730	11.89	1,280,104	11.5
2011	40,398,219.52	18,629,045	21,306,213	0.5274	19,092,006	12.27	1,556,005	10.5
2012	41,599,497.81	17,812,495	20,372,318	0.4897	21,227,180	12.69	1,673,223	9.5
2013	37,834,256.29	14,865,347	17,001,637	0.4494	20,832,619	13.13	1,586,206	8.5
2014	43,308,908.70	15,391,590	17,603,506	0.4065	25,705,402	13.60	1,889,613	7.5
2015	60,792,567.30	19,188,759	21,946,363	0.3610	38,846,204	14.09	2,756,443	6.5
2016	47,739,140.49	13,060,490	14,937,404	0.3129	32,801,736	14.60	2,246,112	5.5

Enbridge Gas Inc.

Account #: 478.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L1.5
ASL: 25
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2017	56,152,165.09	12,867,480	14,716,657	0.2621	41,435,508	15.14	2,737,281	4.5
2018	52,904,201.19	9,647,696	11,034,160	0.2086	41,870,041	15.69	2,668,133	3.5
2019	51,912,471.49	6,917,128	7,911,184	0.1524	44,001,287	16.26	2,705,725	2.5
2020	70,913,720.74	5,805,440	6,639,736	0.0936	64,273,985	16.82	3,820,699	1.5
2021	102,006,967.90	2,870,772	3,283,329	0.0322	98,723,639	17.27	5,717,650	0.5
TOTAL	1,020,910,893.69	410,650,079	469,525,898		551,384,996		39,185,557	

COMPOSITE ANNUAL ACCRUAL RATE	3.84%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.46
COMPOSITE AVERAGE AGE (YEARS)	11.32
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	12.95

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 122

To update the table at Enbridge compendium 16.2, page 4, to reflect changes due to the capital update, and add a column or two indicating the difference between the using the traditional net salvage method and the CDNS with the various discount rates.

Response:

Please see Attachments 1-3. For ease of viewing, page 4 of the Enbridge Gas compendium (Exhibit K16.2) has been broken out into 3 separate attachments, each of which has been updated to reflect the 2024 depreciation provision based on the Capital Update.

A summary of the results is in Table 1.

Table 1
Summary of Depreciation Scenarios

	Concentric Lives and Curves		**Intervenor Lives and Curves**	
($ millions)	**ELG (1)**	**ALG (1)**	**ELG (2)**	**ALG (3)**
CDNS @ 3.75% Concentric proposal	**879.0**	795.6	648.3	561.9
CDNS @ 6.03% Intervenor proposal	n/a	n/a	575.4	499.5
Traditional Method	1,034.1	935.7	686.4	595.5

2024 Depreciation at EGI Proposal	**879.0**
2024 Depreciation at Current Depreciation Rates	**737.1**

Notes
(1) See Attachment 1 for details
(2) See Attachment 2 for details
(3) See Attachment 3 for details

ENBRIDGE GAS INC. DEPRECIATION PROVISION COMPARISON

		EGI PROPOSAL			Traditional Method	
Asset Account	Concentric Recommended Life and Curve (1)	EQUAL LIFE GROUP CDNS 3.75% (2)	AVERAGE LIFE GROUP CDNS 3.75%	ELG vs ALG CDNS 3.75% Variance	EQUAL LIFE GROUP Traditional	AVERAGE LIFE GROUP Traditional
442.00	40-S5	121,037	118,854	(2,182)	121,037	118,854
443.01	45-R4	70,295	65,369	(4,926)	70,295	65,369
443.02	55-R4	245,157	228,866	(16,292)	245,157	228,866
451.00	55-R4	1,103,268	1,070,580	(32,688)	1,103,268	1,070,580
452.00	45-R3	3,164,111	2,570,461	(593,650)	3,601,004	2,978,349
453.00	45-R2.5	5,806,931	4,778,828	(1,028,103)	7,292,157	6,073,164
454.00	40-R2	215,265	164,917	(50,348)	215,265	164,917
455.00	55-R3	9,857,986	8,643,932	(1,214,054)	10,792,028	9,473,352
456.00	40-R4	21,390,221	19,658,806	(1,731,415)	23,117,722	21,282,099
457.00	35-R3	5,389,636	4,714,423	(675,213)	6,399,751	5,555,427
461.00	60-R4	1,558,436	1,457,089	(101,347)	1,558,436	1,457,089
462.00	50-S4	3,442,222	3,338,770	(103,452)	3,731,475	3,581,717
463.00	55-S4	160,119	150,739	(9,380)	179,427	168,748
464.00	30-L0.5	180,907	116,069	(64,838)	191,567	123,224
465.00	60-R4	52,439,913	48,757,344	(3,682,569)	52,439,913	48,757,344
466.00	30-R4	38,709,127	35,588,987	(3,120,140)	41,040,030	37,451,332
467.00	40-R4	15,204,608	14,119,524	(1,085,084)	17,388,414	16,148,824
471.00	60-R4	1,221,703	1,138,109	(83,595)	1,221,703	1,138,109
472.00	40-S0.5	5,945,106	5,358,729	(586,377)	5,945,106	5,358,729
472.31	40-S0.5	1,516,289	1,350,235	(166,054)	1,516,289	1,350,235
472.32	40-S0.5	1,125,018	1,004,164	(120,854)	1,125,018	1,004,164
472.33	40-S0.5	2,684,144	2,670,266	(13,878)	2,684,144	2,670,266
472.34	40-S0.5	798,633	712,552	(86,081)	798,633	712,552
472.35	40-S0.5	2,569,080	2,550,168	(18,912)	2,569,080	2,550,168
473.01	40-S0.5	29,969,149	22,576,607	(7,392,542)	38,478,005	29,900,799
473.02	55-S3	136,735,162	124,004,969	(12,730,194)	174,298,545	157,952,828
474.00	25-SQ	46,298,774	46,298,774	0	46,304,967	46,304,967
475.00	25-SQ	10,469,399	10,469,399	0	10,469,399	10,469,399
475.21	55-R3	129,657,949	113,122,032	(16,535,917)	183,487,258	161,285,502
475.30	60-R4	107,007,350	99,402,770	(7,604,579)	149,782,932	139,104,096
476.00	17-S2.5	482,255	429,221	(53,035)	482,255	429,221
477.00	40-R2	30,924,387	24,955,061	(5,969,326)	32,886,768	26,723,076
477.01	35-R3	5,584,218	4,857,045	(727,173)	5,584,218	4,857,045
478.00	15-S2.5	119,877,761	104,685,609	(15,192,152)	119,877,761	104,685,609
482.00	40-R1.5	302,463	211,833	(90,630)	302,463	211,833
482.01	40-R1.5	5,780,346	5,592,980	(187,366)	5,780,346	5,592,980
482.04	40-R1.5	-	-	0	-	-
482.05	40-R1.5	1,562,381	1,404,042	(158,339)	1,562,381	1,404,042
482.51	40-R1.5	4,945,676	4,258,936	(686,739)	4,945,676	4,258,936
482.52	40-R1.5	3,164,180	3,129,402	(34,778)	3,164,180	3,129,402
483.00	15-SQ	1,732,767	1,889,229	156,462	1,732,767	1,889,229
484.00	12-L2.5	6,708,608	5,440,686	(1,267,922)	6,708,608	5,440,686
485.00	17-L1.5	4,305,666	3,288,351	(1,017,314)	4,305,666	3,288,351
486.00	15-SQ	10,258,875	10,258,875	0	10,258,875	10,258,875
487.70	15-SQ	250,902	250,902	0	250,902	250,902
487.80	20-SQ	352,999	357,020	4,020	352,999	357,020
488.00	10-SQ	2,088,746	2,088,746	0	2,088,746	2,088,746
490.00	4-SQ	3,990,450	4,217,378	226,928	3,990,450	4,217,378
490.00 (Post 2023)	4-SQ	1,958,107	1,958,107	0	1,958,107	1,958,107
490.30	10-SQ	-	-	0	-	-
491.01	4-SQ	10,638,821	10,810,743	171,922	10,638,821	10,810,743
491.01 (Post 2023)	4-SQ	2,158,742	2,158,742	0	2,158,742	2,158,742
491.02	4-SQ	3,730,251	3,824,244	93,993	3,730,251	3,824,244
491.02 (Post 2023)	4-SQ	2,520,837	2,520,837	0	2,520,837	2,520,837
491.03	10-SQ	9,922,379	10,111,622	189,243	9,922,379	10,111,622
Software Intangibles - 10YR	10-SQ			0		
491.04	10-SQ	9,153,052	9,153,052	0	9,153,052	9,153,052
Sub-total		877,451,863	794,054,995	(83,396,868)	1,032,525,277	934,121,749
RNG and Sales-type lease assets		1,532,536	1,532,536	-	1,532,536	1,532,536
2024 DEPRECIATION @ EGI OR INTERVENOR PROPOSED DEPRECIATION RATES		**878,984,399**	**795,587,531**	**(83,396,868)**	**1,034,057,813**	**935,654,285**

2024 DEPRECIATION @ CURRENT DEPRECIATION RATES (3)	**737,115,889**

NOTES

(1) Consistent with Capital Update at Exhibit 2, Tab 5, Schedule 4, Attachment 1

(2) See Exhibit J17.1 for details

(3) See Exhibit J16.5 for details

ENBRIDGE GAS INC. DEPRECIATION PROVISION COMPARISON - EQUAL LIFE GROUP

		EGI PROPOSAL	INTERVENOR PROPOSALS/SCENARIOS			
Asset Account	Concentric Recommended Life and Curve (1)	EQUAL LIFE GROUP CDNS 3.75% (2)	Intervenor Recommended Life and Curve	ELG + Intervenor Life and Curve CDNS 3.75%	ELG + Intervenor Life and Curve CDNS 6.03%	ELG + Intervenor Life and Curve Traditional Method
442.00	40-S5	121,037	N/A	121,037	121,037	121,037
443.01	45-R4	70,295	N/A	70,295	70,295	70,295
443.02	55-R4	245,157	N/A	245,157	245,157	245,157
451.00	55-R4	1,103,268	N/A	1,103,268	1,103,268	1,103,268
452.00	45-R3	3,164,111	45-R2.5	3,018,866	2,756,807	3,346,438
453.00	45-R2.5	5,806,931	N/A	5,806,931	4,767,274	7,292,157
454.00	40-R2	215,265	N/A	215,265	215,265	215,265
455.00	55-R3	9,857,986	N/A	9,857,986	9,324,250	10,792,028
456.00	40-R4	21,390,221	44-R4	17,691,447	16,992,273	19,312,829
457.00	35-R3	5,389,636	40-R2.5	4,192,475	3,627,242	4,988,756
461.00	60-R4	1,558,436	N/A	1,558,436	1,558,436	1,558,436
462.00	50-S4	3,442,222	N/A	3,442,222	3,268,664	3,731,475
463.00	55-S4	160,119	N/A	160,119	150,500	179,427
464.00	30-L0.5	180,907	N/A	180,907	178,773	191,567
465.00	60-R4	52,439,913	70-R4	41,655,295	38,023,130	44,716,522
466.00	30-R4	38,709,127	37-R4	27,719,025	26,832,623	27,275,082
467.00	40-R4	15,204,608	N/A	15,204,608	13,899,142	14,115,311
471.00	60-R4	1,221,703	N/A	1,221,703	1,221,703	1,221,703
472.00	40-S0.5	5,945,106	N/A	5,945,106	5,945,106	5,945,106
472.31	40-S0.5	1,516,289	N/A	1,516,289	1,516,289	1,516,289
472.32	40-S0.5	1,125,018	N/A	1,125,018	1,125,018	1,125,018
472.33	40-S0.5	2,684,144	N/A	2,684,144	2,684,144	2,684,144
472.34	40-S0.5	798,633	N/A	798,633	798,633	798,633
472.35	40-S0.5	2,569,080	40-S0.5 - No Truncation	608,968	608,968	608,968
473.01	40-S0.5	29,969,149	50-L1	19,610,115	15,741,744	26,008,147
473.02	55-S3	136,735,162	60-S3	117,188,759	98,120,890	138,980,603
474.00	25-SQ	46,298,774	50-L1	16,010,475	16,010,475	16,010,475
475.00	25-SQ	10,469,399	N/A	10,469,399	10,469,399	10,469,399
475.21	55-R3	129,657,949	70-R3	80,940,381	61,745,684	87,346,205
475.30	60-R4	107,007,350	70-R2	92,223,647	72,072,932	86,813,990
476.00	17-S2.5	482,255	N/A	482,255	482,255	482,255
477.00	40-R2	30,924,387	N/A	30,924,387	29,480,325	32,886,768
477.01	35-R3	5,584,218	N/A	5,584,218	5,584,218	5,584,218
478.00	15-S2.5	119,877,761	25-L1.5	44,871,902	44,871,902	44,871,902
482.00	40-R1.5	302,463	N/A	302,463	302,463	302,463
482.01	40-R1.5	5,780,346	N/A	5,780,346	5,780,346	5,780,346
482.04	40-R1.5	0	N/A	-	-	-
482.05	40-R1.5	1,562,381	N/A	1,562,381	1,562,381	1,562,381
482.51	40-R1.5	4,945,676	N/A	4,945,676	4,945,676	4,945,676
482.52	40-R1.5	3,164,180	N/A	3,164,180	3,164,180	3,164,180
483.00	15-SQ	1,732,767	N/A	1,732,767	1,732,767	1,732,767
484.00	12-L2.5	6,708,608	N/A	6,708,608	6,708,608	6,708,608
485.00	17-L1.5	4,305,666	N/A	4,305,666	4,305,666	4,305,666
486.00	15-SQ	10,258,875	N/A	10,258,875	10,258,875	10,258,875
487.70	15-SQ	250,902	N/A	250,902	250,902	250,902
487.80	20-SQ	352,999	N/A	352,999	352,999	352,999
488.00	10-SQ	2,088,746	N/A	2,088,746	2,088,746	2,088,746
490.00	4-SQ	3,990,450	N/A	3,990,450	3,990,450	3,990,450
490.00 (Post 2023)	4-SQ	1,958,107	N/A	1,958,107	1,958,107	1,958,107
490.30	10-SQ	0	N/A	-	-	-
491.01	4-SQ	10,638,821	5-SQ	8,274,638	8,274,638	8,274,638
491.01 (Post 2023)	4-SQ	2,158,742	5-SQ	2,158,742	2,158,742	2,158,742
491.02	4-SQ	3,730,251	5-SQ	2,857,540	2,857,540	2,857,540
491.02 (Post 2023)	4-SQ	2,520,837	5-SQ	2,520,837	2,520,837	2,520,837
491.03	10-SQ	9,922,379	N/A	9,922,379	9,922,379	9,922,379
Software Intangibles - 10YR	10-SQ		N/A			
491.04	10-SQ	9,153,052	N/A	9,153,052	9,153,052	9,153,052
Sub-total		877,451,863		646,738,090	573,903,175	684,898,229
RNG and Sales-type lease assets		1,532,536		1,532,536	1,532,536	1,532,536
2024 DEPRECIATION @ EGI OR INTERVENOR PROPOSED DEPRECIATION RATES		**878,984,399**		**648,270,626**	**575,435,711**	**686,430,765**

2024 DEPRECIATION @ CURRENT DEPRECIATION RATES (3)	**737,115,889**

NOTES

(1) Consistent with Capital Update at Exhibit 2, Tab 5, Schedule 4, Attachment 1

(2) See Exhibit J17.1 for details

(3) See Exhibit J16.5 for details

ENBRIDGE GAS INC. DEPRECIATION PROVISION COMPARISON - AVERAGE LIFE GROUP

		INTERVENOR PROPOSALS/SCENARIOS				
Asset Account	Concentric Recommended Life and Curve (1)	ALG + Concentric Life and Curve CDNS 3.75% (2)	Intervenor Recommended Life and Curve	ALG + Intervenor Life and Curve CDNS 3.75%	ALG + Intervenor Life and Curve CDNS 6.03%	ALG + Intervenor Life and Curve Traditional Method
442.00	40-S5	118,854	N/A	118,854	118,854	118,854
443.01	45-R4	65,369	N/A	65,369	65,369	65,369
443.02	55-R4	228,866	N/A	228,866	228,866	228,866
451.00	55-R4	1,070,580	N/A	1,070,580	1,070,580	1,070,580
452.00	45-R3	2,570,461	45-R2.5	2,442,812	2,244,001	2,735,364
453.00	45-R2.5	4,778,828	N/A	4,778,828	3,873,096	6,073,164
454.00	40-R2	164,917	N/A	164,917	164,917	164,917
455.00	55-R3	8,643,932	N/A	8,643,932	8,169,975	9,473,352
456.00	40-R4	19,658,806	44-R4	16,636,390	15,740,817	17,848,713
457.00	35-R3	4,714,423	40-R2.5	3,501,792	3,011,746	4,191,786
461.00	60-R4	1,457,089	N/A	1,457,089	1,457,089	1,457,089
462.00	50-S4	3,338,770	N/A	3,338,770	3,193,003	3,581,717
463.00	55-S4	150,739	N/A	150,739	141,769	168,748
464.00	30-L0.5	116,069	N/A	116,069	114,636	123,224
465.00	60-R4	48,757,344	70-R4	38,830,845	35,461,256	41,667,588
466.00	30-R4	35,588,987	37-R4	25,745,076	24,921,920	25,333,496
467.00	40-R4	14,119,524	N/A	14,119,524	12,913,471	13,114,316
471.00	60-R4	1,138,109	N/A	1,138,109	1,138,109	1,138,109
472.00	40-S0.5	5,358,729	N/A	5,358,729	5,358,729	5,358,729
472.31	40-S0.5	1,350,235	N/A	1,350,235	1,350,235	1,350,235
472.32	40-S0.5	1,004,164	N/A	1,004,164	1,004,164	1,004,164
472.33	40-S0.5	2,670,266	N/A	2,670,266	2,670,266	2,670,266
472.34	40-S0.5	712,552	N/A	712,552	712,552	712,552
472.35	40-S0.5	2,550,168	40-S0.5 - No Truncation	469,928	469,928	469,928
473.01	40-S0.5	22,576,607	50-L1	13,648,887	10,775,189	18,370,688
473.02	55-S3	124,004,969	60-S3	106,499,693	89,249,090	126,227,403
474.00	25-SQ	46,298,774	50-L1	10,870,976	10,870,976	10,870,976
475.00	25-SQ	10,469,399	N/A	10,469,399	10,469,399	10,469,399
475.21	55-R3	113,122,032	70-R3	70,160,355	53,278,547	75,800,690
475.30	60-R4	99,402,770	70-R2	71,821,396	56,132,796	67,542,687
476.00	17-S2.5	429,221	N/A	429,221	429,221	429,221
477.00	40-R2	24,955,061	N/A	24,955,061	23,785,031	26,723,076
477.01	35-R3	4,857,045	N/A	4,857,045	4,857,045	4,857,045
478.00	15-S2.5	104,685,609	25-L1.5	32,953,669	32,953,669	32,953,669
482.00	40-R1.5	211,833	N/A	211,833	211,833	211,833
482.01	40-R1.5	5,592,980	N/A	5,592,980	5,592,980	5,592,980
482.04	40-R1.5	0	N/A	-	-	-
482.05	40-R1.5	1,404,042	N/A	1,404,042	1,404,042	1,404,042
482.51	40-R1.5	4,258,936	N/A	4,258,936	4,258,936	4,258,936
482.52	40-R1.5	3,129,402	N/A	3,129,402	3,129,402	3,129,402
483.00	15-SQ	1,889,229	N/A	1,889,229	1,889,229	1,889,229
484.00	12-L2.5	5,440,686	N/A	5,440,686	5,440,686	5,440,686
485.00	17-L1.5	3,288,351	N/A	3,288,351	3,288,351	3,288,351
486.00	15-SQ	10,258,875	N/A	10,258,875	10,258,875	10,258,875
487.70	15-SQ	250,902	N/A	250,902	250,902	250,902
487.80	20-SQ	357,020	N/A	357,020	357,020	357,020
488.00	10-SQ	2,088,746	N/A	2,088,746	2,088,746	2,088,746
490.00	4-SQ	4,217,378	N/A	4,217,378	4,217,378	4,217,378
490.00 (Post 2023)	4-SQ	1,958,107	N/A	1,958,107	1,958,107	1,958,107
490.30	10-SQ	0	N/A	-	-	-
491.01	4-SQ	10,810,743	5-SQ	8,365,469	8,365,469	8,365,469
491.01 (Post 2023)	4-SQ	2,158,742	5-SQ	2,158,742	2,158,742	2,158,742
491.02	4-SQ	3,824,244	5-SQ	2,931,212	2,931,212	2,931,212
491.02 (Post 2023)	4-SQ	2,520,837	5-SQ	2,520,837	2,520,837	2,520,837
491.03	10-SQ	10,111,622	N/A	10,111,622	10,111,622	10,111,622
Software Intangibles - 10YR	10-SQ		N/A			
491.04	10-SQ	9,153,052	N/A	9,153,052	9,153,052	9,153,052
Sub-total		794,054,995		560,367,558	497,983,730	593,953,403
RNG and Sales-type lease assets		1,532,536		1,532,536	1,532,536	1,532,536
2024 DEPRECIATION @ EGI OR INTERVENOR PROPOSED DEPRECIATION RATES		**795,587,531**		**561,900,094**	**499,516,266**	**595,485,939**

2024 DEPRECIATION @ CURRENT DEPRECIATION RATES (3)	**737,115,889**

NOTES

(1) Consistent with Capital Update at Exhibit 2, Tab 5, Schedule 4, Attachment 1

(2) See Exhibit J17.1 for details

(3) See Exhibit J16.5 for details

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 150

To clarify sources of capital, as described in Ms. Duff's example.

Response:

This response details three scenarios:

1) The current state which describes how net salvage is currently collected, accounted for and used; and
2) Two scenarios in response to Commissioner Duff's example:
    a) What would occur if a segregated fund approach was adopted; and
    b) What would occur if there was a large increase in retirements and associated costs of retirements.

Details of each scenario are described below.

Current state:
Enbridge Gas currently collects amounts for future abandonment within the net salvage component of its depreciation rates. From a regulatory accounting perspective, the amounts collected as part of depreciation expense are included in accumulated depreciation, which results in a reduction to the PP&E component of utility rate base.[1] The reduction to rate base is accelerated as a result of the collection of abandonment costs (or negative net salvage costs) over the life of the asset, as compared to a scenario where depreciation rates do not include a net salvage component. The accelerated reduction of rate base in turn reduces the need for financing (both debt and equity), lowering the carrying charge or cost of capital to customers.

In Exhibit I.4.5-ED-136, part f), Enbridge Gas estimated that the lower rate base has resulted in customers saving approximately $1,029 million between 2013 to 2022.

[1] From a financial statement reporting perspective, the amounts collected are reclassified and presented as a regulatory liability rather than a credit in accumulated depreciation.

Consistent with regulatory treatment, abandonment amounts collected to date have been used to pay for the costs of abandonments/retirements as they occur, and to fund rate base requirements (i.e. to pay down the cost of assets included in rate base), inclusive of working capital, thus lowering the Company's actual financing requirements.

Scenarios to address Commissioner Duff's example:
In reviewing the transcript, it appears there could be two scenarios that Commissioner Duff was referring to. First, what are the financing/capital implications of establishing a segregated fund, and second, what are the financing/capital implications if there was a large increase in retirements and associated costs of retirement.

Establish a segregated fund
In the first scenario, where Enbridge Gas is required to establish a segregated fund for outstanding abandonment costs which have already been collected (as well as for future amounts collected), rate base would need to increase by $1.6 billion. Funds previously collected would no longer be used to finance/pay down rate base, but instead would have to be directed to a segregated fund for the sole use of funding future abandonment costs. This would require accumulated depreciation to be reduced by $1.6 billion (increasing rate base and the associated cost of capital to customers), with an associated transfer of funds to the segregated fund.

In order to perform this transaction, Enbridge Gas would raise $1.6 billion in debt and equity (in alignment with its approved deemed equity ratio). To fund the debt portion, Enbridge Gas would access long term debt markets. To fund the equity portion, Enbridge Gas would seek equity financing through its parent, Enbridge Inc.

Future abandonment costs collected would be directed directly to the segregated fund and would not be reflected as part of depreciation expense or accumulated depreciation. The actual costs for future abandonment work would be withdrawn from the segregated fund.

If the $1.6 billion in previously collected abandonment costs were transferred to a segregated fund, the increase in rate base and associated financing costs would increase the annual revenue requirement to be collected from customers by more than $93 million[2]. In the Company's view, using funds collected through net salvage to offset current customer rates continues to be appropriate, as customers will continue to benefit from reduced costs attributable to a lower rate base. Should the OEB determine that moving these funds from their current use as an offset to rate base is appropriate,

[2] See Exhibit 4, Tab 5, Schedule 1, paragraph 41a) for more details.

phasing in the transition from rate base offset to the segregated fund could be considered to help mitigate the rate impact of this decision.

Large increase in retirements and associated costs of retirement

In the second scenario, where there is a large increase in retirements and associated costs of retirement, the Company believes the existing regulatory accounting treatment would continue. As the costs are incurred, they will reduce accumulated depreciation, thereby increasing rate base, in conjunction with the retirement of the asset.

In a situation where a large increase in retirements and associated costs of retirement is earlier than expected, it could mean that the associated assets were not fully depreciated and that the forecast costs of retirement were not fully recovered through annual depreciation charges. This would result in a reduction to accumulated depreciation, increasing rate base and associated carrying charges to customers, as a result of the higher debt and equity financing that would be required. This would be addressed in a subsequent depreciation study where the unrecovered cost of the retired asset would be reflected in the depreciation rates charged on the remaining assets on a go forward basis.

In a situation where a large increase in retirements and associated costs of retirement was anticipated (e.g. where energy transition implications become clearer and allows the Company to plan accordingly), the Company would expect that depreciation rates would be adjusted in advance of the retirements, such that the recovery of the cost of the asset and associated abandonment are accelerated (such as through the implementation of accelerated depreciation or an economic planning horizon). In the time leading up to the retirement, depreciation charges to ratepayers would be higher, but would be partially offset by a lower cost of capital associated with the accelerated decline in rate base. In this situation, there would be no unrecovered costs of retirement to be reflected in depreciation rates as the retirement would have been planned for.

From a day-to-day operational perspective, given that amounts collected for costs of retirements are not transferred to a segregated fund, but are used to finance/pay down rate base, the day-to-day actual cost of retirements incurred are funded through operational cash flows or through short-term debt (i.e. credit facility).

Should a significant amount of retirements occur unexpectedly and over a relatively short period of time, Enbridge Gas would use a combination of short term liquidity (i.e. commercial paper) and issuance of long term debt. At the same time, equity injections from its parent, Enbridge Inc., would ensure Enbridge Gas maintains its OEB-approved debt to equity ratio. The funds raised would be available for use for retirement activities.

ENBRIDGE GAS INC.

Answer to Undertaking

Undertaking

Tr: 170

To provide a breakdown of where the update and the settlement agreement lead us, in terms of the revenue requirement and the deficiency that is generated, including schedules highlighting the deficiency.

Response:

The current updated 2024 revenue deficiency is $203.3 million, which includes a delivery deficiency of $186.3 million and a gas supply deficiency of $17.0 million[1]. This deficiency reflects the Capital Update and the impacts of the Settlement Proposal. Please see Attachment 1 for the revenue requirement calculation and supporting schedules.

The updated revenue requirement and resultant deficiency reflects the impact of the removal of Dawn to Corunna, the WAMS project overspend opening rate base adjustment, the 25% of GTA project overspend opening rate base adjustment, the removal of GTA West land from opening rate base, and the rate base impact of decreased overheads associated with the reduction to O&M. The cost of capital reduction associated with these adjustments has been calculated using the capital structure filed June 16, 2023, in Exhibit 2, Tab 5, Schedule 4, Attachment 5, page 1. The capital structure is subject to change pending the OEB's decision on the outstanding issues, including capital expenditures and equity thickness, at which point the capital structure will be re-evaluated.

The revenue deficiency for Phase 1 will ultimately be updated pursuant to the OEB’s Decision relating to Phase 1 of this proceeding and reflected in the rate order.

[1] The revenue deficiency has not been adjusted for the gas supply costs that will continue to be recovered in the gas supply deferral and variance accounts with no base rate adjustment in Phase 1. Updates to the gas supply costs in rates will be addressed in Phase 2 and Phase 3 of the Application.

2024 Utility Cost of Capital Summary - Test Year - EGI
Settlement & Capital Update

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)	Cost ($ millions)
		(a)	(b)	(c)	(d) = (b x c)	(e) = (a x c)
1	Long and Medium Term Debt	9,773.4	61.85	4.17	2.58	407.3
2	Short Term Debt	23.7	0.15	3.00	0.00	0.7
3	Common Equity	6,004.7	38.00	8.66	3.29	520.0
4	Total	15,801.8	100.00		5.87	928.1

2024 Utility (Deficiency)/Sufficiency Calculation and Required Rate of Return - Test Year - EGI
Settlement and Capital Update

Line No.	Particulars	Principal ($ millions) (a)	Component (%) (b)	Cost Rate (%) (c)	Cost Component (%) (d) = (b x c)
	Debt				
1	Long and Medium Term Debt (1)	9,773.4	61.85	4.17	2.578
2	Short Term Debt	23.7	0.15	3.00	0.004
3	Total Debt	9,797.1	62.00		2.582
4	Common Equity	6,004.7	38.00	8.66	3.291
5	Total	15,801.8	100.00		5.873
6	Rate Base	15,801.8			
7	Utility Income	778.6			
8	Indicated Rate of Return	4.928%			
9	(Deficiency)/Sufficiency in Rate of Return	(0.946%)			
10	Net (Deficiency)/Sufficiency	(149.4)			
11	Gross (Deficiency)/Sufficiency	(203.3)			
12	Revenue at Existing Rates	6,021.1			
13	Revenue Requirement	6,224.4			
14	Gross Revenue (Deficiency)/Sufficiency	(203.3)			
	Common Equity				
15	Allowed Rate of Return	8.660%			
16	Earnings on Common Equity	6.172%			
17	(Deficiency)/Sufficiency In Common Equity Return	(2.488%)			

2024 Test Year - Calculation of Total Revenue Deficiency
Settlement & Capital Update

Line No.	Particulars ($ millions)	Reference	Delivery	Gas Supply	Total
	Cost of Capital				
1	Rate Base	Exhibit 2 Tab 1 Schedule 1	15,801.8		15,801.8
2	Required Rate of Return	Exhibit 5 Tab 2 Schedule 1 Attachment 6	5.87%		5.87%
3	Required Return		928.1		928.1
	Cost of Service				
4	Gas Costs	Exhibit 4 Tab 2 Schedule 1 Attachment 1	17.6	3,204.9	3,222.5
5	Operations and Maintenance	Exhibit 4 Tab 4 Schedule 1	1,004.0	-	1,004.0
6	Depreciation and Amortization	Exhibit 4 Tab 5 Schedule 1 Attachment 2	866.2	-	866.2
7	Fixed Financing Costs	Exhibit 5 Tab 2 Schedule 1	4.0	-	4.0
8	Municipal and Other Taxes	Exhibit 4 Tab 6 Schedule 2	125.6	-	125.6
9	Total		2,017.4	3,204.9	5,222.3
	Miscellaneous Operating and Non-Operating Revenue				
10	Other Operating Revenue	Exhibit 3 Tab 1 Schedule 1	(64.3)	-	(64.3)
11	Other Income	Exhibit 3 Tab 1 Schedule 1	-	-	-
12	Total		(64.3)	-	(64.3)
	Income Taxes on Earnings				
13	Excluding Tax Shield	Exhibit 4 Tab 6 Schedule 1 Attachment 1	197.1	(4.5)	192.6
14	Tax Shield Provided by Interest Expense	Exhibit 4 Tab 6 Schedule 1 Attachment 1	(108.1)	-	(108.1)
15	Total		89.0	(4.5)	84.5
	Taxes on (Deficiency)/Sufficiency				
16	Gross (Deficiency)/Sufficiency		(186.3)	(17.0)	(203.3)
17	Net (Deficiency)/Sufficiency		(136.9)	(12.5)	(149.4)
18	Total		49.4	4.5	53.9
19	Revenue Requirement		3,019.5	3,204.9	6,224.4
20	Revenue At Existing Rates				
21	Gas Sales	Exhibit 3 Tab 2 Schedule 1 Attachment 3	2,671.0	3,185.4	5,856.4
22	Transmission, Compression & Storage	Exhibit 3 Tab 4 Schedule 1 Attachment 1	162.2	2.5	164.7
23	Total Revenue At Existing Rates		2,833.2	3,187.9	6,021.1
24	Gross Revenue (Deficiency) (1)		(186.3)	(17.0)	(203.3)

Note
(1) PREP has been excluded from the revenue deficiency calculation because it will be recovered via the levelized approach. The levelized deficiency attributable to 2024 would be $7.3 million.

2024 Net Utility Income - EGI
Settlement & Capital Update

Line No.	Particulars ($ millions)	Test Year
	Operating Income	
1	Gas Sales and Distribution	5,856.4
2	Transportation	164.7
3	Storage	0.0
4	Other Operating Revenue	64.3
5	Interest and Property Rental	-
6	Other Income	-
7	Total Operating Revenue	6,085.4
	Operating Cost	
8	Gas Costs	3,222.5
9	Operation and Maintenance	1,004.0
10	Depreciation and Amortization Expense	866.2
11	Fixed Financing Costs	4.0
12	Debt Redemption Premium Amortization	0.0
13	Municipal and Other Taxes	125.6
14	Cost of Service	5,222.3
15	Utility Income Before Income Taxes	863.1
16	Income Tax Expense	(84.5)
17	Utility Income	778.6

2024 Test Year - Drivers of Delivery Revenue Deficiency

Line No.	Particulars ($ millions)	Gross (Deficiency)/ Sufficiency	Relative Contribution
1	Net sustainable synergies and productivity	74.2	(40%)
2	Changes in accounting policy and methodologies	25.6	(14%)
3	Impact related to ICM and Capital Pass Through	(42.0)	23%
	Deferred Rebasing Impact	57.8	(31%)
4	Cost pressures	(111.9)	60%
5	Higher depreciation resulting from new depreciation study	(187.5)	101%
6	Increase equity thickness from 36% to 38% in 2024	(26.1)	14%
	Cost of Service Impacts	(325.5)	175%
7	Removal NBV of WAMS	3.3	(2%)
8	Removal 25% NBV of GTA overspend	3.4	(2%)
9	Defer Dawn- Corunna to Phase 2	22.5	(12%)
10	Adjustment to customer addition forecast	4.1	(2%)
11	Reduction of O&M by $50M	50.0	(27%)
12	GTA Land Removal from Opening ratebase	1.7	(1%)
13	Overhead Capitalization decrease as a result of settled O&M	(3.6)	2%
	Settled Items	81.4	(44%)
14	Total Gross 2024 Test Year Deficiency	(186.3)	100%

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 109

To calculate additional fuel requirements required for compression purposes in order to deliver the same heat value of hydrogen in relation to the same heat value of methane.

Response:

At this point, Enbridge Gas is unable to complete compressor fuel calculations due to the complexity and time of performing this evaluation which may also require working with compressor manufacturers.

As part of the System-Wide Hydrogen Blending Study, system modelling will be performed to determine the effects of adding hydrogen to the gas supply (up to and including 100% hydrogen) and the required reinforcements, retrofits, and upgrades for transmission and distribution assets, including compression facilities and any changes to compressor fuel requirements.

Clarification Question:

/u

Subsequent to filing undertakings on August 18, 2023, Enbridge Gas received clarification questions via a letter from the OEB in relation to the undertakings. In its letter dated August 29, 2023, the OEB states that they have reviewed Enbridge Gas's response to Undertaking J18.3 and clarifies the information request as follows:

a) Recognizing that one cubic meter of hydrogen has approximately one third of the heat value of one cubic meter of methane at standard temperature and pressure, provide the work required, in joules, to compress hydrogen gas so that one cubic meter of hydrogen delivers the same heat value as one cubic meter of methane.

b) In general terms, please comment on the amount of energy that would be required to compress one cubic meter of gas to meet the average operating pressures experienced in Enbridge Gas's intermediate, high, and extra-high pressure networks as the percentage of hydrogen gas blended with natural gas increases to 100%.

Clarification Response:

From research papers and articles, it is recognized that as you increase the percent of hydrogen content in natural gas, the power consumption also increases.[1] The work required to compress the equivalent amount of 100% hydrogen to deliver the same energy as methane, assuming all other factors are equal - which is a very limited applicable scenario, is approximately three times more[2]. While it is possible to calculate the work to compress hydrogen gas so that one cubic metre of hydrogen delivers the same heat value as one cubic metre of methane, this simplified calculation does not take into account real-world considerations that are required to produce a credible and meaningful response. At best, this value would be theoretical and not representative of the piping network under review. There are many factors that contribute to the amount of work to affect effective compression of hydrogen, such as but not limited to: temperature, gas density, flow rate, inlet and outlet pressures of a compressor, head losses and compressor efficiency.

Within the Enbridge Gas distribution network, where there are multiple pressure tiers, calculating the energy required to compress variations of blended gas up to and including 100% hydrogen becomes more complex as a centralized compression facility may not be the manner in which compression is undertaken. A hydrogen compression system may be comprised of a distributed pure hydrogen network where different entities could inject hydrogen into the gas distribution network at different locations.

Although there are many methods of producing hydrogen, the prevailing technology for making low carbon hydrogen is by use of an electrolyzer which can produce pure hydrogen at relatively high pressures. Enbridge Gas's hydrogen blending pilot in Markham uses a PEM (Proton Exchange Membrane) electrolyzer which produces hydrogen at a pressure of 31bar (~450psi) which is higher than the maximum operating pressure of that portion of the distribution system, thus requiring pressure reduction instead of compression of the hydrogen. As such, depending upon the hydrogen generation technology being used, compression may not be required and could be reduced across the system in a distributed scenario, resulting in distributed savings. Approximately 95% of Enbridge Gas's total pipeline lengths have maximum operating pressures nearly equal to or less than the hydrogen pressure produced from typical PEM electrolyzers thus enabling a large reach of the network in which hydrogen compression would not be required.

For instance, hydrogen produced from a typical PEM electrolyzer being injected onto the following pressure networks would result in:

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[1] Kurz, R., Cowell, L., Vignal, M. (September 2020) Hydrogen in Pipelines, *Pipeline Technology Journal*, Issue 3, pp.64-72. https://www.pipeline-journal.net/ejournal/ptj-3-2020/#0
[2] Ibid.

- No hydrogen compression required for low and intermediate pressure networks;
- No hydrogen compression required for high pressure networks;
- Potential for hydrogen compression for extra-high pressure networks, which would require specific considerations to determine the required work to compress; and
- A likely need for hydrogen compression for the limited number of pipelines operating above extra-high pressure, which would require specific considerations to determine the required work to compress.

With the proposed Hydrogen Blending Grid Study, Enbridge Gas intends to verify and validate energy requirements to move hydrogen and natural gas blends at different percentages through different pipeline configurations, temperatures, flow rates, etc., to understand how this can be done within Enbridge Gas's specific system and identify what retrofits may be needed for system optimization. Enbridge Gas intends to share any early findings with the OEB in its proposed interim report and further findings in a final report through the Hydrogen Blending Grid Study.

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 110

To file the scoping document for the Hydrogen Study.

Response:

The scoping document of the Hydrogen Blending Study is currently under development. As mentioned in evidence, "the scope of the Hydrogen Blending Study will include the establishment of the system's baseline in its current state: understanding where and how much hydrogen can be accommodated, understanding hydrogen tolerance constraints, and identifying and implementing grid enhancements to enable the system to accept maximum tolerable amounts of hydrogen to achieve the greatest reductions of GHG emissions in a safe and cost-effective manner"[1]. As described in the Asset Management Plan in Exhibit 2, Tab 6, Schedule 2, Appendix A, "the assessment comprises the entirety of EGI's gas pipeline network in Ontario: 78, 214 km of gas distribution main lines, 66,787 km of gas distribution service lines, and 5,471 km of gas transmission lines".[2]

The scope of work will be executed in a structure that follows the code requirements in *CSA Z662 Oil & Gas Pipeline System*s in *Clause 3.4 Engineering Assessments*[3]. The structure will also incorporate Enbridge Gas's approach to hydrogen blending which centers on four key elements[4]:

1. Assessment of existing gas distribution/transmission network;
2. Assessment of existing end-user network, appliances, and equipment;
3. Operational readiness and reliability of supply; and
4. Integrity and risk management.

[1] Exhibit 4, Tab 2, Schedule 2, p.17.
[2] Exhibit 2, Tab 6, Schedule 2, Appendix A, p.29.
[3] CSA Z662:2023 Oil and gas pipeline systems, is available for purchase through the Canadian Standards Association: https://www.csagroup.org/store/product/CSA%20Z662:23/
[4] Exhibit 4, Tab 2, Schedule 6, p.8-9.

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 110

Assuming 100,000 residential customers depart the system over the next three years, with potentially stranded connection facilities, meters, regulators and services to the street: (a) to assess impact on curves associated with those classes of assets; (b) to assess impact on revenue requirement if the depreciation expenses accelerated to accommodate that change, to prevent stranded costs.

Response:

The following response was provided by Concentric Energy Advisors:

Concentric modelled the response to this undertaking with the following assumptions:

- The residential customers depart the system in equal numbers over a three-year period (effectively 33,333 customers per year) between 2021 to 2023.
- Customers departed the system after an average of 17 years starting in 2021, to align with the approximate life span of a natural gas furnace. This assumption is an attempt to provide aged retirements that would mirror a realistic scenario for many families. This resulted in retirements in the 3 years between 2021-2023 related to vintages from 2003-2005.
- The cost to add a customer is assumed to be $5,991, which is a proxy based on a response to Exhibit J13.8.
- The cost of retirement is expected to be $1,300, based off EGD's historical cost for cut-off at main.
- Concentric used the CPI index to deflate the original cost of $5,991 back to the proposed year of installation.
- Costs were allocated between accounts as follows[1]:
    - 473.01 – 6%
    - 473.02 – 56%
    - 474.00 – 4%
    - 475.21 – 7%
    - 475.30 – 18%

[1] See Exhibit J13.16.

- 477.00 – 5%
- 477.01 – 1%
- 478.00 – 3%

Based on the above assumptions, Concentric re-ran the actuarial analysis for all accounts impacted by this analysis. The resultant Iowa curves are included as Attachment 1. Concentric would not recommend any change to the proposed Iowa curves based on this analysis.

Concentric calculated the depreciation impact of the reduction in original cost balance and accumulated depreciation accounts using the proposed average service life, Iowa curves, and net salvage estimates as proposed by Concentric in this study. The rates were calculated using the Equal Life Group procedure, using the Constant Dollar Net Salvage approach with a discount rate of 3.75%. Overall, the composite depreciation expense increased from 3.61% as proposed in the Capital Update[2] to 3.72%. The depreciation rate for Distribution assets increased from 3.73% to 3.89%. This change is summarized in Table 1.

Table 1
Updated Depreciation Rates Reflecting Scenario from Commissioner Moran

Account	Description	Updated Original Cost (at 12/31/2021)	Updated Accumulated Depreciation (at 12/31/2021)	Accrual Rate[2]	Updated Accrual Rate
473.01	Services – Metal	$526,888,522	$237,766,043	4.43%	4.80%
473.02	Services – Plastic	$4,246,458,722	$1,099,608,961	2.73%	2.92%
474.00	Regulators	$473,697,749	$39,485,712	8.86%	9.51%
475.21	Mains – Coated & Wrapped	$3,293,865,261	$1,015,705,968	3.38%	3.43%
475.30	Mains – Plastic	$3,411,826,711	$836,752,566	2.72%	2.78%
477.00	Measuring & Regulating Equipment	$931,989,621	$342,420,955	2.89%	2.95%
477.01	Customer M&R Equipment	$139,933,686	$47,001,174	3.34%	3.59%
478.00	Meters	$1,009,531,007	$454,246,011	10.25%	10.56%

Enbridge Gas has calculated that the 2024 revenue requirement would increase by $34.1 million after applying the updated accrual rates in Table 1 to the 2024 forecast asset balances. This impact would increase further if the trend in customers departing the system were to continue beyond 2023.

The following response was provided by Enbridge Gas:

Enbridge Gas has provided an additional table for consideration which illustrates the potential impact on depreciation expense if Economic Planning Horizons (EPH) were

[2] Exhibit 2, Tab 5, Schedule 4, Attachment 1.

applied in the various revenue horizon scenarios shown in Exhibit K10.2 page 139 and as updated in Exhibit J10.11. Table 2 presents the increase in the 2024 depreciation expense if an EPH which corresponds to the customer connection revenue horizon (40, 30, 25, 20, 15 and 10 years) is applied on the plastic services account.

Table 2
Depreciation Impact After Applying EPH on Plastic Services Based on Revenue Horizon Scenarios

($ millions)	2024	10-year	15-year	20-year	25-year	30-year
	(a)	(b)	(c)	(d)	(e)	(f)
Depreciation expense on plastic services	136.8	748.0	499.8	350.5	250.6	200.6
Increase in depreciation vs 2024 forecast (column a)	-	611.2	363.0	213.7	113.8	63.8

Notes:

(1) Based on EPH rates provided by Concentric.

(2) Assumes EPH applies to existing and new assets under plastic services.

(3) The depreciation base for plastic services is approximately $5 billion.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021

Related to Total Expense

Account		Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LOCAL STORAGE PLANT											
442.00		STRUCTURES AND IMPROVEMENTS	0	40-S5	0%	6,282,181	2,805,060	3,477,121	105,928	24.7	1.69%
443.01		HOLDER - STORAGE TANK	0	45-R4	0%	5,804,412	4,023,544	1,780,869	55,594	19.1	0.96%
443.02		HOLDER EQUIPMENT	0	55-R4	0%	21,554,522	11,363,396	10,191,126	229,183	36.8	1.06%
TOTAL LOCAL STORAGE PLANT						**33,641,115**	**18,192,000**	**15,449,115**	**390,705**		1.16%
UNDERGROUND STORAGE PLANT											
451.00		LAND RIGHTS INTANGIBLE	0	55-R4	0%	74,762,354	45,841,825	28,920,529	1,102,904	23.0	1.48%
452.00		STRUCTURES AND IMPROVEMENTS	0	45-R3	-10%	104,433,820	47,148,032	67,729,170	2,964,640	23.7	2.84%
453.00		WELLS	0	45-R2.5	-30%	143,144,395	50,040,540	136,047,173	5,515,551	25.9	3.85%
454.00		WELL EQUIPMENT	0	40-R2	0%	13,364,517	8,575,936	4,788,581	175,831	21.4	1.32%
455.00		FIELD LINES	0	55-R3	-8%	201,920,080	53,298,115	164,775,572	5,130,627	33.4	2.54%
456.00		COMPRESSOR EQUIPMENT	0	40-R4	-6%	682,328,757	228,311,196	494,957,286	19,661,453	25.5	2.88%
457.00		REGULATING AND MEASURING EQUIPMENT	0	35-R3	-14%	77,194,133	51,829,828	36,171,484	2,003,634	15.6	2.60%
TOTAL UNDERGROUND STORAGE PLANT						**1,297,148,055**	**485,045,470**	**933,389,796**	**36,554,640**		2.82%
TRANSMISSION PLANT											
461.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	88,171,402	20,599,533	67,571,869	1,507,598	44.3	1.71%
462.00		COMPRESSOR STRUCTURES AND IMPROVEMENTS	0	50-S4	-5%	163,351,958	40,353,631	131,165,925	3,377,914	37.7	2.07%
463.00		MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	0	55-S4	-6%	11,252,284	7,167,268	4,760,153	157,646	26.2	1.40%
464.00		EQUIPMENT	0	30-L0.5	-5%	2,920,218	523,642	2,542,587	160,081	15.8	5.48%
465.00		MAINS	0	60-R4	-12%	2,783,251,797	919,330,147	2,197,911,866	49,201,674	42.3	1.77%
466.00		COMPRESSOR EQUIPMENT	0	30-R4	-7%	1,005,060,039	331,530,582	743,883,660	37,417,456	19.6	3.72%
467.00		MEASURING AND REGULATING EQUIPMENT	0	40-R4	-15%	395,646,542	119,798,512	335,195,011	12,112,032	27.7	3.06%
TOTAL TRANSMISSION PLANT						**4,449,654,239**	**1,439,303,314**	**3,483,031,070**	**103,934,401**		2.34%
DISTRIBUTION PLANT											
471.00		LAND RIGHTS INTANGIBLE	0	60-R4	0%	63,907,560	12,099,619	51,807,941	1,150,753	45.2	1.80%
472.00	*	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-S0.5	0%	220,832,605	64,014,227	156,818,378	7,005,487	21.7	3.17%
472.31		STRUCTURES AND IMPROVEMENTS - STONEY CREEK	2046	40-S0.5	0%	29,662,115	5,056,171	24,605,944	1,325,428	18.6	4.47%
472.32		STRUCTURES AND IMPROVEMENTS - WIN-RHODES	2046	40-S0.5	0%	23,216,546	5,549,955	17,666,591	991,735	17.9	4.27%
472.33		STRUCTURES AND IMPROVEMENTS - LONDON ADMIN	2026	40-S0.5	0%	19,789,902	9,778,917	10,010,985	2,365,393	4.2	11.95%
472.34		STRUCTURES AND IMPROVEMENTS - KINGSTON OFFICE	2046	40-S0.5	0%	16,737,576	4,069,504	12,668,072	704,663	18.0	4.21%
472.35		STRUCTURES AND IMPROVEMENTS - MAINWAY	2027	40-S0.5	0%	15,937,297	3,958,252	11,979,045	2,264,210	5.3	14.21%
473.01		SERVICES - METAL	0	40-S0.5	-32%	526,888,522	237,766,043	457,726,806	25,316,970	19.0	4.80%
473.02		SERVICES - PLASTIC	0	55-S3	-26%	4,246,458,722	1,099,608,961	4,250,929,029	124,144,291	35.8	2.92%
474.00		REGULATORS	0	25-SQ	0%	473,697,749	39,485,712	434,212,038	45,052,878	15.8	9.51%
475.00		MAINS - ENVISION	0	25-SQ	0%	181,264,676	59,887,548	121,377,128	10,469,399	12.2	5.78%
475.21		MAINS - COATED & WRAPPED	0	55-R3	-42%	3,293,865,261	1,015,705,968	3,661,582,702	112,952,984	35.0	3.43%
475.30		MAINS - PLASTIC	0	60-R4	-38%	3,411,826,711	836,752,566	3,871,568,295	94,986,369	42.1	2.78%
476.00		COMPANY NGV COMPRESSOR STATIONS	0	17-S2.5	0%	9,878,703	5,181,735	4,696,968	365,238	9.7	3.70%
477.00		MEASURING AND REGULATING EQUIPMENT	0	40-R2	-9%	931,989,621	342,420,955	673,447,732	27,464,018	23.3	2.95%
477.01		CUSTOMER M&R EQUIPMENT	0	35-R3	0%	139,933,686	47,001,174	92,932,512	5,026,559	19.4	3.59%
478.00		METERS	0	15-S2.5	0%	1,009,531,007	454,246,011	555,284,996	106,601,810	6.4	10.56%
TOTAL DISTRIBUTION PLANT						**14,615,418,258**	**4,242,583,317**	**14,409,315,162**	**568,188,185**		3.89%

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021

Related to Total Expense

Account	Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
GENERAL PLANT										
482.00	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-R1.5	0%	13,255,572	8,677,610	4,577,962	191,336	23.2	1.44%
482.01	STRUCTURES AND IMPROVEMENTS - VPC	2033	40-R1.5	0%	53,463,354	19,270,729	34,192,626	3,400,629	10.0	6.36%
482.04	STRUCTURES AND IMPROVEMENTS - THOROLD	2022	40-R1.5	0%	15,678,640	6,391,978	9,286,662	9,286,663	0.5	59.23%
482.05	STRUCTURES AND IMPROVEMENTS - MARKHAM	2046	40-R1.5	0%	36,671,818	6,852,980	29,818,839	1,544,848	19.3	4.21%
482.51	STRUCTURES AND IMPROVEMENTS - KEIL HEAD OFFICE	2049	40-R1.5	0%	69,558,675	11,589,939	57,968,736	3,906,954	16.4	5.62%
482.52	STRUCTURES AND IMPROVEMENTS - BLOOMFIELD TRAINING CENTER	2028	40-R1.5	0%	19,237,692	1,664,764	17,572,928	2,814,701	6.2	14.63%
483.00	OFFICE FURNITURE AND EQUIPMENT	0	15-SQ	0%	29,776,062	20,323,396	9,452,666	1,200,881	6.0	4.03%
484.00	TRANSPORTATION EQUIPMENT	0	12-L2.5	0%	134,722,078	89,525,829	45,196,249	6,268,747	5.7	4.65%
485.00	HEAVY WORK EQUIPMENT	0	17-L1.5	0%	44,128,921	12,811,266	31,317,655	3,658,037	8.6	8.29%
486.00	TOOLS AND WORK EQUIPMENT	0	15-SQ	0%	79,966,854	26,128,214	53,838,641	9,529,666	7.6	11.92%
487.70	RENTAL - REFUEL APPL	0	15-SQ	0%	864,755	92,164	772,591	86,895	9.3	10.05%
487.80	RENTAL - NGV STATIONS	0	20-SQ	0%	7,774,175	2,397,143	5,377,032	288,265	18.4	3.71%
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	0	10-SQ	0%	11,224,609	4,990,530	6,234,079	2,946,627	2.6	26.25%
490.00	COMPUTER EQUIPMENT	0	4-SQ	0%	30,306,679	20,774,567	9,532,112	4,041,429	1.7	13.34%
	COMPUTER EQUIPMENT - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
490.30	COMPUTER EQUIPMENT - WAMS	0	10-SQ	0%	4,680,899	2,418,465	2,262,435	502,763	4.5	10.74%
491.01	SOFTWARE ACQUIRED INTANGIBLES	0	4-SQ	0%	155,164,785	107,550,337	47,614,448	13,604,128	2.0	8.77%
	SOFTWARE ACQUIRED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.02	SOFTWARE DEVELOPED INTANGIBLES	0	4-SQ	0%	38,776,288	25,519,357	13,256,930	3,892,471	2.2	10.04%
	SOFTWARE DEVELOPED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.03	CIS ACQUIRED SOFTWARE	0	10-SQ	0%	87,626,214	20,250,171	67,376,042	7,217,716	8.4	8.24%
**	SOFTWARE INTANGIBLES - 10 YEAR	0	10-SQ	0%	0	0	0	0	0.0	10.00%
491.04	WAMS	0	10-SQ	0%	85,221,905	44,031,318	41,190,587	9,153,464	4.5	10.74%
TOTAL GENERAL PLANT					**918,099,975**	**431,260,756**	**486,839,219**	**83,536,220**		9.10%
TOTAL UTILITY PLANT STUDIED					**21,313,961,643**	**6,616,384,857**	**19,328,024,362**	**792,604,151**		**3.72%**
PLANT NOT STUDIED										
401.00	Franchises and Consents - Total Comp				1,175,081					
402.04	Other Intangibles - Lakeland Acquisition Adjustment				494,761					
458.00	Base Pressure and Line Pack Gas				76,135,052					
	Land (Including MacLeod Property)				177,293,391					
	Plant Held for Future Use				1,670,861					
	Inventory Adjustment				59,309,971					
***	Post Study Adjustments				5,005,525					
TOTAL PLANT NOT STUDIED					**321,084,642**					
TOTAL UTILITY PLANT IN SERVICE					**21,635,046,285**					

* Annual Accrual Rates for new major structures in Account 472.00 after 2023 are 4.02%.

** New depreciation rate for major longer term intangible asset additions post 2023

*** Adjustments between regulated and unregulated storage operations to align with updated exhibits in Enbridge Gas's 2021 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding (EB-2022-0110), as filed on September 2, 2022

ENBRIDGE GAS INC.

Answer to Undertaking from
Commissioner Moran

Undertaking

Tr: 111

To explain the duration and frequency over the past five years of minus 15 and colder temperatures in the Union South and Enbridge GTA service areas.

Response:

Table 1 summarizes the number of instances within the last five years (between August 12, 2018, to August 12, 2023) where temperatures have fallen to -15°C or colder[1].

"Average Gas Day" represents the number of instances of -15°C or colder after averaging all hours throughout the gas day for each respective day within the past five years.

"Hourly" represents the number of instances -15°C or colder for all hours in the past five years.

Table 1
Number of Instances where Temperature is -15°C or colder in past five years

Line No.	Service Area	Weather Station	Station Location (Latitude, Longitude)	Average Gas Day	Hourly
		(a)	(b)	(c)	(d)
1	Union South	London[2]	London International Airport (43.03, -81.15)	9	353
2	Enbridge GTA	Toronto	Toronto International Airport (43.68, -79.63)	12	325

[1] Temperature and windspeed data are gathered from Environment Canada for each weather station. They are then used to calculate the windspeed compensated temperatures. The data provided within the tables and figures of this undertaking reflect windspeed compensated temperature.
[2] London Station is being used as a proxy for all southwestern Ontario for the results shown in Table 1 as the data is readily available.

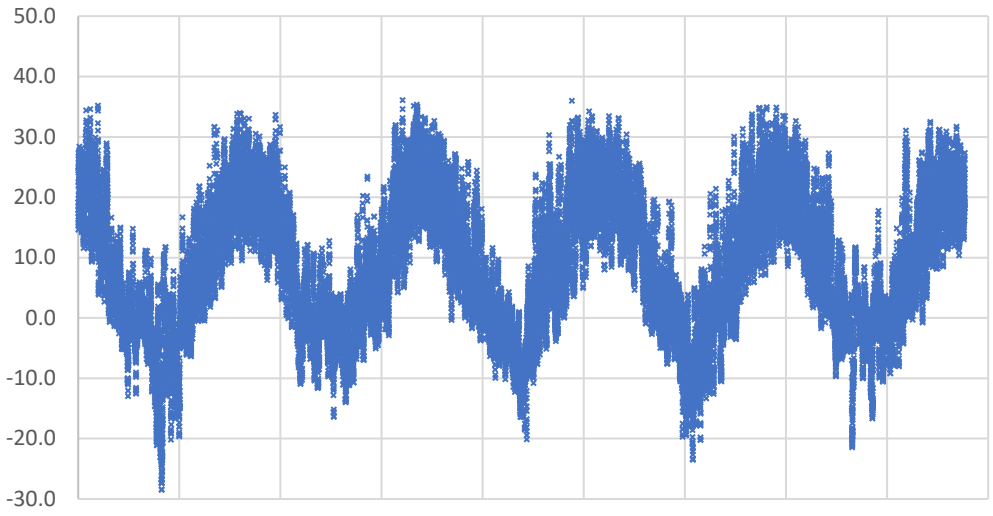
Table 2 below summarizes the Proposed Design Day HDDw for each station and its equivalent Windspeed Compensated Temperature for reference.

Table 2
Weather Station Proposed Design Day Windspeed Compensated Temperature

Line No.	Service Area	Weather Station	Proposed HDDw[3]	Equivalent Windspeed Compensated Temperature (°C)
		(a)	(b)	(c)
1	Union South	London	40.8	-25.8
2	Enbridge GTA	Toronto	41.4	-26.4

Figure 1 and Figure 2 below show the hourly temperature data in Celsius from August 12, 2018, to August 12, 2023.

Figure 1: London Hourly Temperatures from August 12, 2018, to August 12, 2023



[3] Exhibit 4, Tab 2, Schedule 3, Page 18 of 34, Table 1, lines 2 and 4.

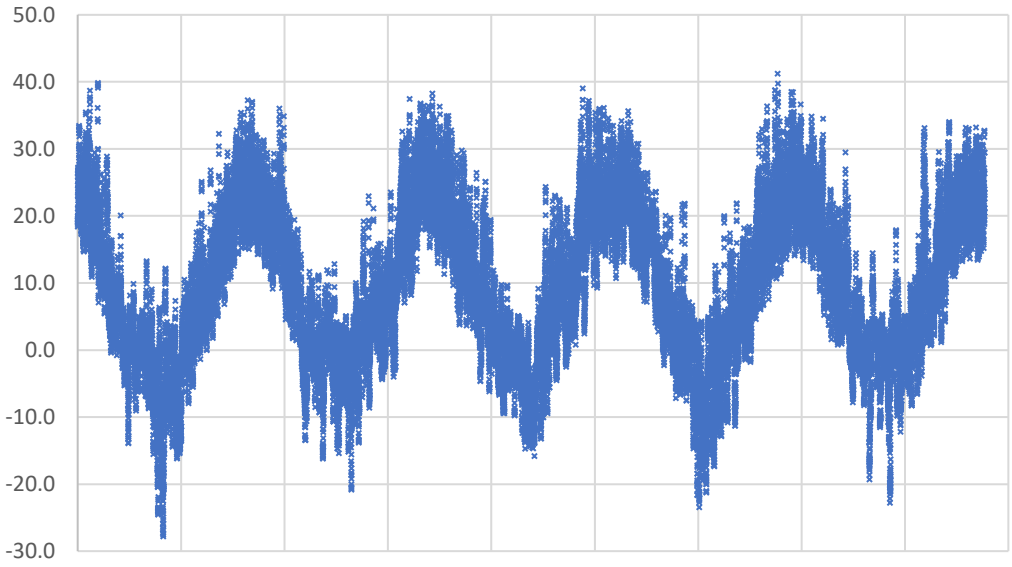



Figure 2: Toronto Hourly Temperatures from August 12, 2018, to August 12, 2023