Vanessa Innis
Program Director
Strategic Regulatory Applications – Rebasing
Regulatory Affairs

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EGIRegulatoryProceedings@enbridge.com

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

April 26, 2024

VIA RESS AND EMAIL

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas, or the Company)
EB-2024-0111 - 2024 Rebasing and IRM – Phase 2 Evidence

Enbridge Gas filed its 2024 Rates Application and the majority of its supporting evidence on October 31, 2022 and the balance of its evidence on November 30, 2022 under docket number EB-2022-0200. In this Application, Enbridge Gas requested approval of rates for the sale, distribution, transmission, and storage of gas commencing January 1, 2024. Enbridge Gas also applied for approval of an incentive rate-setting mechanism (IRM) for the years from 2025 to 2028. The proceeding was split into three phases through the OEB's Decision on the Issues List (Procedural Order No. 2 in Phase 1) and the subsequent Settlement Agreement reached amongst the parties.

Phase 1 of the proceeding was completed with a December 21, 2023 Decision and Order, and a May 1, 2024 Interim Rate Order. The OEB subsequently issued EB-2024-0111 as the new docket number for Phase 2 of the proceeding. On April 4, 2024 Enbridge Gas filed a letter stating Phase 2 evidence would be filed April 26, 2024.

Enclosed is the evidence required to address the issues included in Phase 2. Those issues include: (i) the Phase 1 issues that were deferred to Phase 2 as a result of the Settlement Agreement; (ii) the Phase 2 issues identified in Procedural Order No. 2 (other than Issues 54-57, which are for Phase 3); and (iii) the items from the Phase 1 Decision that Enbridge Gas is expected to address and/or report on in Phase 2 of the rebasing proceeding.

The Administration exhibit provided at Phase 2 Exhibit 1, Tab 3, Schedule 1 provides background information and further detail of the evidence provided, with attachments containing the requested approvals and the OEB directives from the Phase 1 Decision and from past proceedings addressed in evidence. The requested approvals are very similar to what had been included in the Phase 1 evidence and reserved for Phase 2.

The new requested approvals (as compared to what was previously requested and reflected in the Issues List approved in Phase 1) are the following: (i) inclusion of Dawn to Corunna project costs in rate base; (ii) approval of two new deferral and variance accounts – an OEB Cost Assessment Variance Account and an OEB Directive Deferral Account; and (iii) a change to the calculation of the Meter Reading Performance Metric.

A list of all Phase 2 exhibits is provided at Phase 2 Exhibit 1, Tab 1, Schedule 1. Attachment 3 to the Administration exhibit (Exhibit 1, Tab 3, Schedule 1) includes a mapping of the Phase 2 issues (as identified in the EB-2022-0200 Issues List) to the evidence filed for Phase 2.

As part of Phase 2, Enbridge Gas is requesting approval of updated 2024 rates effective January 1, 2024. The OEB approved interim 2024 rates in the Phase 1 Interim Rate Order issued on April 11, 2024 for implementation on May 1, 2024. Enbridge Gas is proposing to update the interim 2024 rates to reflect the OEB's Phase 2 findings as part of the Phase 2 draft rate order process.

The 2024 bill impacts for individual customers from the approvals requested in Phase 2 vary by rate zone and rate class. For a typical residential sales service customer, the updated 2024 rates, reflecting the Phase 2 proposals, result in an annual bill increase of:

- $3.14 (or 0.2% of total bill) for a Rate 1 customer in the EGD rate zone;
- $3.73 (or 0.3% of total bill) for a Rate 01 customer in the Union North rate zone; and
- $2.75 (or 0.3% of total bill) for a Rate M1 customer in the Union South rate zone.

Given the timing of this Phase 2 process which will set the rate adjustment mechanism for 2025 to 2028 rates, Enbridge Gas will be requesting, if necessary, that 2025 rates be set on an interim basis as of January 1, 2025 until the updated rates can be reviewed and approved. Enbridge Gas will be requesting that any new 2025 rates, when approved and implemented, be recovered on a full-year basis. To allow for new rates to be set as soon as possible, Enbridge Gas expects that it will propose that the 2025 rates be set during the Phase 2 rate order process (perhaps as a separate step).

Enbridge Gas will post the evidence on its website at www.enbridgegas.com/about-enbridge-gas/regulatory. Enbridge Gas will send a copy of this letter, and a link to the website page, to all parties to the proceeding.

Should you have any questions, please let us know.

Sincerely,

[Original Signed by]

Vanessa Innis
Program Director, Strategic Regulatory Applications – Rebasing

EXHIBIT LIST

*Not previously filed in Phase 1 (EB-2022-0200).

*Not previously filed in Phase 1 (EB-2022-0200).

*Not previously filed in Phase 1 (EB-2022-0200).

*Not previously filed in Phase 1 (EB-2022-0200).

CURRICULUM VITAE OF
GILMER BASHUALDO-HILARIO

Experience:	Enbridge Gas Inc.
	Manager Demand Forecasting & Analysis 2023
	Manager Economic Evaluation & Forecast 2019
	Union Gas Limited.
	Manager Demand Forecasting & Analysis 2015
	Senior Advisor Demand Forecasting & Analysis 2005
	Northern Lima Hydro-Edelnor (currently Enel) – Lima, Peru
	Senior Auditor 2001
	Manager Meter Shop Department 2000
	Manager Commercial Process Department 1998
	Manager Billing Department 1997
	Commercial Analyst 1995
	Central Hydro-Electrocentro – Huancayo, Peru
	Financial Analyst 1994
Education:	MBA - San Ignacio de Loyola University, Lima - Peru (2000)

	Master of Arts in Economics - National Agrarian La Molina University, Lima - Peru (2000)
	Bachelor of Arts in Economics - National Agrarian La Molina University – Lima, Peru (1993)
Memberships:	None
Appearances:	(Ontario Energy Board)
	EB-2022-0200

CURRICULUM VITAE OF
CORA CARRIVEAU

Experience:	Enbridge Gas Inc.
	Supervisor, Climate Policy 2024
	Supervisor, Carbon and Energy Transition Planning 2023
	Specialist, Carbon and Energy Transition Planning 2020
	Specialist, Technology and Development, 2019
	Union Gas Limited.
	Principal Geoscientist, Technology and Innovation 2016
	Project Manager, Market Development 2013
Education:	Bachelor of Science, Honours Geology and Environmental Science University of Western Ontario (1999)
	Masters of Engineering Science, Civil and Environmental Engineering University of Western Ontario (2002)
Memberships:	Association of Professional Geoscientists of Ontario
Appearances:	None

CURRICULUM VITAE OF
MOHAMED CHEBARO

Experience:	Enbridge Gas Inc. Director, Integrity and Risk 2022 Senior Strategist, Operations 2022 Manager, Electrical Controls and Energy Systems 2019 Enbridge Gas Distribution Inc. Manager, Engineering 2017 Gazifère Inc. (an Enbridge Company) Manager, Operations 2015 Enbridge Liquids Pipelines Inc. Senior Engineer, Supervisor, Manager, Integrity 2011 C-FER Technologies Inc. Engineer in Training to Research Engineer 2005
Education:	Bachelor of Science (Mechanical Engineering) University of Alberta (2005) Master of Arts (Leadership) University of Guelph (2022)
Memberships:	Professional Engineers Ontario The Association of Professional Engineers and Geoscientists of Alberta The Project Management Institute

Appearances: (Régie de l’énergie – Québec)

Requête 3969-2016

CURRICULUM VITAE OF
STEVE DANTZER

Experience:	Enbridge Gas Inc.
	Supervisor, Gas Supply Planning 2020
	Supervisor, Upstream Regulation 2019
	Union Gas Limited
	Specialist, Carbon 2018
	Program Manager, Cap and Trade 2016
	Project Manager, Upstream Regulation 2013
	Team Lead, General Accounting 2012
	Team Lead, Affiliate Reporting 2010
	Senior Analyst, Financial Reporting 2008
Education:	Chartered Professional Accountant, Chartered Accountant (2006)
	Honours Business Commerce University of Windsor (2004)
Memberships:	Chartered Professional Accountants Canada Chartered Professional Accountants of Ontario
Appearances:	(Ontario Energy Board)
	EB-2017-0255

CURRICULUM VITAE OF
DANIELLE DREVENY

Experience:	Enbridge Gas Inc.
	Manager, Rate Design 2023
	Manager, Capital Financial Planning & Analysis 2019
	Union Gas Limited
	Manager, Operating & Maintenance 2017
	Team Lead, Operating & Maintenance 2015
	Analyst, Operating & Maintenance 2009
	Siemens VDO Automotive
	Business Development Analyst 2002
	Union Gas Limited
	Fulfillment Support Analyst 2001
Education:	Bachelor of Commerce University of Windsor (2001)
Memberships:	None
Appearances:	(Ontario Energy Board)
	EB-2022-0200

CURRICULUM VITAE OF
TANYA FERGUSON

Experience:	Enbridge Gas Inc.
	Vice President, Finance and Business Partner GDS 2020
	Enbridge Gas Distribution Inc.
	Director, Financial Planning and Analysis, GDS 2017
	Enbridge Gas Distribution Inc.
	Manager, Procurement Operations, Supply Chain Management 2013
	Manager Customer Care Operations, Customer Care 2010
	Manager Customer Care Financial Administration, Customer Care 2006
	Manager Special Projects, Customer Care 2005
Education:	Masters of Business Administration Schulich School of Business, York University (2002)
	Certified Professional Accountant Certified Professional Accountants of Ontario (2000)
	Honours Bachelor of Commerce University of Windsor (1996)
Memberships:	Certified Professional Accountant Certified Professional Accountants of Ontario
Appearances:	(Ontario Energy Board) EB-2022-0200

CURRICULUM VITAE OF
STEPHANIE FIFE

Experience:	Enbridge Gas Inc.
	Manager, New Energy Supply 2024
	Manager, Performance Reporting & Analytics 2018
	Union Gas Limited
	Performance Specialist, Portfolio and Planning 2017
	SAP Project Manager 2013
	Integrated Supply Planning Specialist, Gas Supply Planning 2010
	Sr. IT Audit Consultant 2008
	Business Information Specialist, Customer Support 2005
	Web Specialist 1999
Education:	Master of Business Administration Sandermoen School of Business, University of Fredericton (2015)
	Bachelor of Commerce, Honours Business Administration, University of Windsor (2009)
	Bachelor of Arts, Honours, University of Guelph (1997)
Memberships:	None

Appearances: None

CURRICULUM VITAE OF
JASON GILLETT

Experience:	Enbridge Gas Inc.
	Director, S&T Business Development and Sales 2024
	Director, S&T Business Development 2023
	Director, Gas Supply 2020
	Manager, Strategic and Power Markets 2019
	Union Gas Limited
	Strategic Markets Account Manager 2016
	Manager, Upstream Regulation 2015
	Manager, Transportation Acquisition 2014
	Manager, Planning and Technology 2009
	IT Project and Operations Manager 2007
	Application Developer 2003
Education:	Bachelor of Science, Computer Science Western University (2003)
Memberships:	None
Appearances:	(Ontario Energy Board)
	EB-2022-0157 EB-2020-0091 EB-2015-0166

(Canada Energy Regulator)

RH-001-2016

CURRICULUM VITAE OF
RACHEL GOODREAU

Experience:

Enbridge Gas Inc

Manager, Revenue and Cost of Gas
2019

Manager, Revenue
2018

Union Gas Limited

Manager, Financial Planning & Analysis
2017

Manager, Accounts Payable Projects
2016

Team Lead, Accounts Payable
2011

Capacity Utilization Planner, Capacity Management & Utilization
2007

NOVA Chemicals

Coordinator, Accounts Payable
2002

Labour Contracts Administrator, Accounts Payable
2000

King Agro Inc./Pride Seeds

Accountant
1999

Education:

Certified Management Accountant (2002)

Bachelor of Arts in Business
Redeemer University (2000)

Memberships:	Certified Public Accountants - Ontario Certified Public Accountants - Canada
Appearances:	None

CURRICULUM VITAE OF
JANE HUANG

Experience:	Enbridge Gas Inc. Supervisor, Technology Development C&I 2022
	Supervisor, DSM Sales Commercial Market 2020
	Enbridge Gas Distribution Inc. Advisor, DSM Program Design C&I 2016
	Manitowoc Foodservices Project Manager, Strategic Projects 2012
	ZENN Motor Company Project Engineering Manager 2009
	General Motors Canada Project Engineer 2000
Education:	Master of Business Administration, Business York University (2009)
	Master of Applied Science, Mechanical Engineering University of Toronto (1999)
	Bachelor of Engineering, Mechanical Engineering Xi’an Jiaotong University (1997)
Memberships:	Professional Engineers Ontario Certified Energy Manager, Association of Energy Engineers Project Management Professional, Project Management Institute
Appearances:	None

CURRICULUM VITAE OF
DAVE JANISSE

Experience:	Enbridge Gas Inc.
	Manager, Gas Supply Acquisition 2022-Present
	Technical Manager, Leave to Construct Applications 2021-2022
	Supervisor, Gas Supply 2020-2021
	Specialist, S&T Sales 2019-2020
	Union Gas Limited
	Senior Advisor, Strategic Sales 2018-2019
	Senior Buyer, Carbon Markets 2017-2018
	Senior Buyer, Gas Supply 2015-2017
	Buyer, Gas Supply 2014-2015
	Financial Planning & Forecast Analyst 2012-2014
	Financial Analyst, CA Stream 2010-2012
Education:	Honours Bachelor of Commerce University of Windsor (2010)
Memberships:	CPA Ontario: Chartered Professional Account, Chartered Accountant
Appearances:	EB-2017-0255

CURRICULUM VITAE OF
LYNN LEE

Experience:

Enbridge Gas Inc.

Manager Utility Performance & Strategic Reporting, ULT Strategy
2023 – current

Manager, EGI Sync PMO & Strategy
2019 – 2023

Union Gas Limited

Manager, Customer Strategy & Strategic Marketing Initiatives - Marketing
2019

Manager, Strategic Marketing Initiatives – Marketing & Energy Conservation
2018 - 2019

Manager, Strategic Initiatives – Utilities Coordination Team
2018

Manager, Strategic Initiatives – Marketing & Energy Conservation
2017 - 2018

Manager, O&M Capital, and Strategic Projects – Finance
2015 – 2017

Manager, Strategic Projects, and Business Support – Finance
2013 - 2015

Change Management Lead and Business Liaison – Streamline Project II – Finance
2012 – 2013

Union Gas Business Unit Liaison – Streamline Project I - Finance
2012

Manager, Strategic Projects – Business Development Storage & Transportation (BDS&T)
2009 – 2012

Manager, Demand Side Management (DSM) Tracking & Reporting
2006 – 2009

Assistant Manager, Meter Reading – Customer Care
2004 – 2006

Meter Reading Coordinator – Operations
2002 – 2003

Strategic Business Specialist – BDS&T
1999 – 2002

Storage & Transportation Nominations Analyst – BDS&T
1997 – 1999

Customer Relations Representative – Billing & Credit
1996 - 1997

Education:	Bachelor of Arts, Psychology University of Windsor (1992) Bachelor of Commerce, Business Administration University of Windsor (1999)
Memberships:	None
Appearances:	None

CURRICULUM VITAE OF
MICHAEL MCGIVERY

Experience:

Enbridge Gas Inc.

Director, Work Management & Operations Support
2024

Director, Distribution Protection
2023

Manager, Distribution Protection
2019

Enbridge Gas Distribution Inc.

Supervisor, Operations Survey
2016

Sewer Safety Program Manager, Damage Prevention
2014

Field Manager, Damage Prevention
2011

Operations Supervisor, Operations
2010

Special Projects Supervisor, Planning
2007

Pipeline Inspector, Construction
2005

Labour/Gas Technician, Operations
2003

Education:

Master of Business Administration
Clarkson University (2013)

Bachelor of Commerce
Ryerson University (2008)

Business Diploma
George Brown College (2004)

Memberships:	Gas Pipeline Inspector, Technical Standards & Safety Authority (TSSA)
	Chair, Ontario One Call Operations Committee
	Board of Directors, Ontario Regional Common Ground Alliance
Appearances:	None

CURRICULUM VITAE OF
AMY MIKHAILA

Experience:

Enbridge Gas Inc.

Director, Gas Supply
2024

Manager, Policy & Sales Support
2023

Manager, Rate Design
2019

Union Gas Limited

Manager, Rates & Pricing
2015

Manager, Plant Accounting
2012

Manager, Plant Accounting
2012

Team Lead, General Accounting
2009

Senior Coordinator, Operations Budgets
2006

Ernst & Young LLP

Assurance Manager
2005

Senior Staff Accountant
2003

Staff Accountant
2001

Education:

Honours Business Administration, University of Western Ontario (2001)

Memberships:	Chartered Professional Accountants of Canada Chartered Professional Accountants of Ontario Illinois Department of Financial and Professional Regulation, Registered Certified Public Accountant
Appearances:	(Ontario Energy Board) EB-2022-0200 EB-2017-0306/0307 EB-2016-0296 EB-2016-0186

CURRICULUM VITAE OF
JENNIFER MURPHY

Experience:	Enbridge Gas Inc.
	Manager, Carbon and Energy Transition Planning 2022 – present
	Supervisor, Carbon Strategy 2019 – 2022
	Enbridge Gas Distribution Inc.
	Climate Policy/Cap and Trade Compliance Sr. Advisor 2017 – 2019
	Environmental Senior Advisor, Carbon Strategy 2016 – 2017
	Environmental Advisor 2015 – 2016
	Environmental Specialist 2007 – 2015
	SKD Automotive Group
	Environmental Management System Coordinator 2002 – 2007
Education:	Bachelor of Science in Environmental Engineering University of Guelph (2003)
	Environmental Science Technician Sheridan College (1997)
Memberships:	Professional Engineers of Ontario
Appearances:	(Ontario Energy Board)
	EB-2022-0200 EB-2017-0224 EB-2016-0300

CURRICULUM VITAE OF
STEVEN PARDY, P. ENG.

Experience:	Enbridge Gas Inc.
	Manager, Underground Storage & Transmission Planning 2024
	Manager, Underground Storage & Reservoir Engineering 2019 - 2024
	Union Gas Limited
	Manager, Underground Storage & Reservoir Engineering 2015 - 2019
	Transmission Pipeline and Storage Manager 2014 – 2015
	Manager, Business Development 2011 – 2013
	Manager Reservoir and Drilling Engineering 2006 – 2011
	Senior/Principal Reservoir and Drilling Engineer 1998 – 2006
	Intermediate Reservoir Engineer 1997 – 1998
	Storage Reservoir Engineer 1995 – 1997
	Assistant to Storage Planning Engineer 1993 – 1995
Education:	Bachelor of Applied Science Honours Industrial Engineering Co-op University of Windsor (1993)
Memberships:	Professional Engineers of Ontario

Appearances: (Ontario Energy Board)

RP-1999-0047

CURRICULUM VITAE OF
MARK PROCIW

Experience: Enbridge Gas Inc.

Supervisor, Large Commercial Industrial Accounts, Distribution In-Franchise Sales
2020

Sr. Advisor, Large Commercial Industrial Accounts, Distribution In-Franchise Sales
2019

Union Gas Limited

Account Manager, Commercial/Industrial Accounts
2018

Account Representative, Commercial / Industrial Demand-Side Management
2015

Coordinator, Residential / Commercial Sales
2014

Specialist, Low-Income Marketing
2011

Coordinator, Residential Program Delivery
2010

Analyst, Integrated Gas Supply
2009

Analyst, Contracting
2007

Education: Bachelor of Commerce, Minor in Economics

McMaster University (2006)

Memberships: None

Appearances: None

CURRICULUM VITAE OF
RYAN SMALL

Experience:

Enbridge Gas Inc.

Technical Manager, Regulatory Accounting
2019

Enbridge Gas Distribution Inc.

Manager, Regulatory Accounting
2018

Manager, Revenue and Regulatory Accounting
2016

Manager, Regulatory Accounting
2014

Senior Analyst, Regulatory Accounting
2006

Analyst, Regulatory Accounting
2004

Supervisor, Gas Cost Reporting
2001

Senior O&M Clerk
2000

Bank Reconciliation Clerk
1999

Accounting Trainee
1998

Education:

Chartered Professional Accountant, Certified Management Accountant

Chartered Professional Accountants of Ontario (2014)

The Society of Management Accountants of Ontario (2003)

Diploma in Accounting
Wilfrid Laurier University (1997)

Bachelor of Arts in Economics
The University of Western Ontario (1996)

Appearances: (Ontario Energy Board)

EB-2022-0200
EB-2012-0459

CURRICULUM VITAE OF
ADAM STIERS

Experience:	Enbridge Gas Inc.
	Manager, Capacity Utilization and Unaccounted for Gas 2024
	Manager, Unaccounted for Gas 2023
	Manager, Regulatory Applications – Leave to Construct 2021
	Union Gas Limited
	Technical Manager, Regulatory Applications 2017
	Specialist, Strategic Accounts 2015
	Project Manager, Business Development 2014
	Coordinator, Strategic Sales 2011
	Buyer, Gas Supply 2010
	Specialist, Gas Management Services 2009
	Coordinator, Gas Supply 2008
Education:	Masters of Business Administration University of Windsor
	Honours Bachelor of Commerce - Business Administration University of Windsor

Appearances: (Ontario Energy Board)

EB-2020-0091

CURRICULUM VITAE OF
MATT THOMAS, P. Eng

Experience:	Enbridge Gas Inc.
	Manager, Storage & Transportation Business Development 2023
	Specialist, Storage & Transportation Business Development 2021
	Sr. Advisor, Storage & Transportation Business Development 2019
	Union Gas Limited
	Account Manager, Storage & Transportation Sales – Strategic Accounts 2017
	Account Manager, Storage & Transportation Sales – Marketer Services 2014
	Engineer, Gas Control & Capacity Planning 2013
	Engineer/Engineer in Training – Stations – Electrical & Controls 2009
Education:	Bachelor of Applied Science, Honours Electrical Engineering University of Windsor (2009)
Memberships:	Professional Engineers of Ontario
Appearances:	EB-2022-0157

CURRICULUM VITAE OF
MICHELLE TIAN

Experience:	Enbridge Gas Inc.
	Manager, Capital FP&A 2024
	Enbridge Gas Distribution Inc.
	Supervisor, Capital Management 2018
	Capital Management & Plant Accounting Manager 2015
	Operations Reporting Manager 2013
	Supervisor, Operations Accounts Receivable 2011
	Senior Financial Analyst 2008
	Finance Associate 2007
Education:	Bachelor of Commerce, Honours Queen’s University (2006)
Memberships:	Chartered Professional Accountants of Ontario
Appearances:	None

CURRICULUM VITAE OF
EHI UWAGBOE

Experience:	Enbridge Gas Inc. Manager Engineering Construction 2024 Manager of Projects 2021 Riversdale Resources Project Manager 2020 ExxonMobil Engineering Supervisor 2018 Strategic Planning Supervisor 2016 Project Engineer and Project Manager 2007
Education:	Master of Business Administration, MBA Indiana University (2017) Bachelor of Science, Chemical Engineering University of Lagos (2006)
Memberships:	Professional Engineer, APEGA Association of Professional Engineers and Geoscientist of Alberta Project Management Professional, PMP Project Management Institute, PMI
Appearances:	None

CURRICULUM VITAE OF
JASON VINAGRE

Experience:

Enbridge Gas Inc.

Manager, Regulatory Accounting
2020

Manager, Power Accounting
2019

Union Gas Limited

Manager UPO (Utility and Power Operations), Special Projects
2018

Manager, Financial Reporting and Accounting
2016

Manager, Cost of Gas
2013

Team Lead, Cost of Gas
2011

Team Lead, IFRS
2008

Senior Analyst, Financial Reporting
2007

Coco Paving Ltd

Lead Accountant
2006

Roth Mosey LLP

Senior Associate
2005

PricewaterhouseCoopers LLP

Associate, Senior Associate
2000

Education:	Bachelor of Commerce, Honours Business Administration, University of Windsor (2000)
Memberships:	CPA (Chartered Professional Accountant), Institute of Chartered Accountants of Ontario (2012) CA (Chartered Accountant), Institute of Chartered Accountants of Ontario (2004)
Appearances:	(Ontario Energy Board) EB-2022-0200

CURRICULUM VITAE OF
CARA-LYNNE WADE

Experience:	Enbridge Gas Inc.
	Director Energy Transition Planning & Energy Conservation 2024
	Director, Energy Transition Planning 2022
	Manager, Energy Transition Planning 2021
	Manager, Marketing & Customer Insights 2019
	Union Gas Limited
	Manager, Energy Conservation Policy & Strategy 2017
	Manager, Marketing Communications 2016
	Manager, DSM Program Design & Delivery - Low Income (LI) Market 2013
	Manager, DSM Program Design & Delivery – Residential Market 2011
	Program Lead, DSM Program Design & Delivery – Commercial & Industrial Market 2009
	Specialist, DSM Program Design & Delivery – Commercial & Industrial Market 2007
Education:	Masters in Business Administration (MBA) Schulich School of Business, York University

	Honours Business Administration (HBA) Richard Ivey School of Business, University of Western
Memberships:	None
Appearances:	(Ontario Energy Board)
	EB-2022-0200

CURRICULUM VITAE OF
RYAN WERENICH

Experience:	Enbridge Gas Inc.
	Manager, Integrity Programs - Pipelines 2023 – Present
	Manager, Operations 2015 – 2023
	Manager, Engineering Design and Construction 2011 - 2015
Education:	Bachelor of Engineering and Management McMaster University (2002)
Memberships:	Professional Engineers of Ontario
Appearances:	None

CURRICULUM VITAE OF
MELINDA YAN

Experience:	Enbridge Gas Inc. Manager, Operations & Maintenance 2023
	Supervisor, Operations & Maintenance 2020
	Enbridge Gas Distribution Inc. Specialist, Finance Alignment 2018
	Supervisor, Business Performance 2015
	Supervisor, Internal Audit 2012
	Manager, Internal Controls 2010
	Accenture Inc. Manager, Control Assurance 2008
	CAA South Central Ontario Senior Auditor 2005
Education:	Chartered Professional Accountant, Certified General Accountant (CPA, CGA) Chartered Professional Accountants of Ontario, 2014 Certified General Accountants of Ontario, 2007
	Certified Fraud Examiner (CFE), Association of Certified Fraud Examiners, 2012
	Certified Internal Auditor (CIA), Institute of Internal Auditors, 2010

	Bachelor of Business Administration (BBA) University of Toronto, 2003
Appearances:	(Ontario Energy Board) EB-2022-0200

Lawrence Kaufmann

Resume

April 2024

Address: 12520 Central Park Drive
Austin, Texas 78732
(608) 443-9813 (cell)

Education:

Ph.D.:	Economics, University of Wisconsin-Madison, 1993
BA & MA:	Economics, University of Missouri-Columbia, 1984
High School:	St. Louis University High, St. Louis, MO, 1980

Relevant Work Experience, Primary Positions:

February 2021 – present: President, LKaufmann Consulting, Consultant to and Subcontractor with Black & Veatch Consulting

December 2008 – February 2021: President, LKaufmann Consulting
Senior Advisor, Pacific Economics Group and Navigant Consulting
Fellow, Canadian Energy Research Institute

Advise companies and public agencies, particularly energy utilities and regulators, on various regulatory and industry restructuring issues. Duties include consultation on performance-based regulation (PBR), developing service quality incentive plans, analyzing appropriate code of conduct policies for competitive markets, and providing supporting empirical research. Duties involve preparing public testimony and written reports, overseeing empirical research, client contact and briefings, and public presentations.

January 2001– December 2008: Partner, Pacific Economics Group, Madison, WI
November 1998 – December 2000: Vice President, Pacific Economics Group, Madison, WI

Advise energy utilities and regulators on various industry restructuring issues. Duties include consultation on performance-based regulation (PBR), developing service quality incentive plans, analyzing appropriate code of conduct policies for competitive markets, and providing supporting empirical research. Duties involve preparing public testimony and written reports, overseeing empirical research, client contact and briefings, and public presentations.

August 1993 – October 1998: Senior Economist, Christensen Associates, Madison, WI

Assisted in the development and evaluation of PBR plans for energy utilities and other regulated enterprises. Duties included theoretical and empirical research (including the estimation of total factor productivity trends), written reports, client contact and briefings, public presentations, and monitoring regulatory trends in the United States and overseas.

January 1993 - July 1993:	Research Assistant to Dr. Robert Baldwin, Department of Economics, University of Wisconsin-Madison

Project investigated whether dumping penalties imposed by the United States have led to a diversion of imports from the nations on which the duties were assessed to other exporters.

January 1991 - May 1993:	Dissertation research on the impact of foreign investment on Mexican firms.

Dissertation examined whether there has been any spillover of advanced multinational technologies to competing Mexican firms. Research included development of a theoretical model of spillovers through Mexican recruitment of multinational personnel, interviews and data collection in Mexico, and empirical tests of theoretical conclusions. Dissertation research was funded through a fellowship from the Mellon Foundation.

June 1989 - December 1990:	Research Associate, Credit Union National Association, Madison, WI

Initiated and assisted on several long-term research projects, including the assessment of capital positions at Corporate credit unions, comparing the asset portfolios of credit unions and banks, and analysis concerning the development of credit union industries in Poland and Costa Rica.

January 1988 - August 1988:	Investment Banking Officer and Associate Economist, Centerre Bank, St. Louis, MO
April 1985 - December 1987:	Assistant Economist, Centerre Bank, St. Louis, MO

As Assistant Economist, the primary duty was to prepare country risk reports on nations to which the bank was lending. As Associate Economist and Investment Banking Officer, duties expanded to include writing a twice-weekly column on interest rate trends and preparing special reports on regional, national and international economic trends for senior management.

August 1983 - December 1984 and four semesters during the period September 1988 - May 1993:

Teaching assistant for classes in introductory microeconomics, introductory macroeconomics, international economics and the history of economic thought.

Professional Memberships:	American Economic Association National Association of Business Economists
Foreign Language Proficiency:	Spanish

Major Consulting Projects:

1. Plan design, productivity factors, customer growth discounts, and cost benchmarking in support of an incentive regulation plan, Fortis BC, 2023-2024
2. Plan design, policy testimony, and cost benchmarking in support of a performance-based regulation plan, National Grid, 2023-2024

3. Plan design, policy testimony, total factor productivity and cost benchmarking in support of a performance-based regulation plan, EGI, 2021-2023.
4. Plan design, policy testimony, cost benchmarking in support of a performance-based regulation plan. Berkshire Gas, 2021-2022.
5. Plan design, policy testimony, cost benchmarking in support of a performance-based regulation plan. Eversource Energy, 2021-2022.
6. Advise on appropriate labor and consumer price indices in labor compensation dispute. Crescent River Port Pilots' Association.
7. Plan design, policy testimony and cost benchmarking study in support of performance-based regulation plan. National Grid/Boston Gas, 2020-2021.
8. Advice on PBR strategy and application. Fortis BC, 2018-2020.
9. Policy testimony and cost benchmarking study in support of performance-based regulation plan. National Grid/Massachusetts Electric, 2018-2019.
10. Confidential advice on regulatory strategy. Client wishes to remain anonymous at this time, 2018.
11. Advice on regulatory environment and investment strategy. Client wishes to remain confidential at this time, 2017-2018.
12. Escalators for operating and construction expenses. Epcor Water West, 2017-18.
13. Rebuttal testimony on cost and wage benchmarking. Puerto Rice Electric Power Authority, 2016-2017.
14. Review and respond to comments on Epcor Water testimony. Epcor Water, 2016.
15. Review of regulatory framework to encourage efficient investment and accommodate uncertainty. Client wishes to remain confidential at this time, 2016.
16. Assessment of Ontario Power Generation ratemaking proposal. Ontario Energy Board, 2016.
17. Testimony on cost and wage benchmarking. Puerto Rico Electric Power Authority, 2016.
18. Testimony recommending updated inflation escalators in performance-based regulation plan. Epcor Water, 2015-2016.
19. Testimony recommending productivity factor for updated performance-based regulation plan. Epcor Water, 2015-2016.
20. Finalize reliability standards for electricity distributors in Ontario. Ontario Energy Board, 2015-2016.
21. Testimony on benefits of expanding bidding process for expansion of Alliant Riverside Energy Center facility. Associated Builders and Contractors of Wisconsin, 2015.
22. Cost benchmarking study. Puerto Rico Electric Power Authority, 2015.
23. Multi-client "Utility of the Future" and PBR study. Clients wish to remain confidential at this time, 2015.
24. Advise on benchmarking methods for electricity distribution. ANEEL, Brazilian Electricity Regulatory Agency, 2014.

25. The impact of gas extension tariffs on the development of the CNG market in Wisconsin. Reinhart Boerner Van Deuren on behalf of Kwik Trip, 2014.
26. TFP study and review of price controls in New Zealand. New Zealand Electricity Network Association, 2014.
27. Advise on benchmarking and regulatory issues in Toronto Hydro Custom IR application. Ontario Energy Board, 2014-15.
28. Advise on interrogatory responses. Consumer Energy Coalition of British Columbia, 2014.
29. Survey and analysis of implementation issues associated with customer-specific reliability metrics. Ontario Energy Board, 2013-15.
30. Empirical analysis and recommendation of appropriate reliability benchmarks. Ontario Energy Board, 2013-15.
31. Cost of service review (transmission and distribution operations) and cost benchmarking for Israel Electric Corporation. Public Utility Authority of Israel, 2013-15.
32. Value of reliability improvements from undergrounding power lines. Wisconsin Public Service, 2013.
33. Advise on and assess gas distribution incentive regulation plans. Ontario Energy Board, 2013-14.
34. Advise on price control application. UK Power Networks, 2013.
35. Advise on electricity distribution incentive regulation plans and other aspects of renewed regulatory framework for electricity. Ontario Energy Board, 2012-13.
36. Response to Productivity Commission Report on Energy Network Regulatory Frameworks. Energy Safe Victoria, 2012.
37. Statement on appropriate opt-out policies for smart meters to Wisconsin Public Service Commission. SMART Water, 2012.
38. Submission to Australia’s Productivity Commission on the role of benchmarking in utility regulation. Energy Safe Victoria, 2012.
39. Assist Staff on review of cost of service applications for Enbridge Gas Distribution and Union Gas. Ontario Energy Board, 2012.
40. Assist with responses on data requests in testimony on alternative regulation plan. Potomac Electric Power, 2011-12.
41. Assess incentive regulation plans for Union Gas and Enbridge Gas Distribution in Ontario. Ontario Energy Board, 2011.
42. Advise on demand-side management and decoupling plans, and utility involvement in conservation and renewable energy businesses. ATCO Gas, 2011.
43. Advise on defining and measuring utility performance and the use of performance measures and standards in electric utility regulation. Ontario Energy Board, 2011-12.
44. Advise on rate mitigation strategies. Ontario Energy Board, 2011.
45. Advise on PBR strategy in Alberta. EDTI, 2011-12.

46. Estimate total factor productivity trend for gas distributors in New Zealand. Powerco, on behalf of industry, 2011.
47. Evaluation of reliability standards and alternative regulatory approaches for maintaining the reliability of electricity supplies. Ontario Energy Board, 2010-12
48. Prepare submission on rule change application and respond to consultant reports on TFP spreadsheet simulations and the impact of the regulatory framework on energy safety. Energy Safe Victoria, 2010.
49. Research on operating productivity and input price changes and testimony in support of an incentive-based formula to recover changes in gas distribution operating expenses. National Grid, 2010.
50. Prepare submission on rule change application and respond to consultant reports on TFP methodology. Essential Services Commission, 2010.
51. Advise on submission on rule change application. Victoria Department of Primary Industries, 2010.
52. Productivity research Victoria gas distribution industry, Essential Services Commission, 2010.
53. Productivity research Victorian power distribution industry, Essential Services Commission, 2010.
54. Advise on revenue decoupling and alternative regulatory strategies in context of upcoming gas distribution rate case. Northwest Natural Gas, 2009-2010.
55. Advise on revenue decoupling. Ontario Energy Board, 2009-2010.
56. Develop a “top down,” econometrically-based measure of reductions in gas consumption resulting from utility DSM programs, and evaluate the merits of this approach compared to the existing “bottom up” methodology. Ontario Energy Board, 2009-2010.
57. Respond to proposals to amend National Energy Regulatory Framework to allow alternative approaches to incentive regulation. Essential Services Commission, 2009-2010.
58. Evaluate consultant reports and prepare submission on the update of price control formulas. New Zealand Energy Network Association, 2009.
59. Evaluate consultant reports in review on alternate regulatory arrangements. Essential Services Commission 2009.
60. Estimate TFP trend for New Zealand electricity distributors. New Zealand Energy Network Association 2009.
61. Evaluate consultant reports in review on alternate regulatory arrangements. Essential Services Commission 2009.
62. Submission on the application of total factor productivity in utility network regulation. Essential Services Commission, 2008-09.
63. Estimate total factor productivity trends, benchmark gas distribution cost performance, and testify in support of research. Bay State Gas, 2008-09.
64. Advise on appropriate regulatory treatment of early termination fees in retail energy markets. Essential Services Commission, 2008.

65. Advise on appropriate regulation of gas connection charges. Essential Services Commission, 2008.
66. Advise on appropriate cost of capital. Jamaica Public Service, 2008.
67. Estimate total factor productivity trends and benchmark bundled power cost performance for use in a productivity based regulation plan. Jamaica Public Service, 2008.
68. Estimate gas distribution total factor productivity trends. Essential Services Commission, 2008.
69. Update estimate total factor productivity trends electricity distributors. Essential Services Commission, 2008.
70. Respond to productivity and benchmarking studies. New Zealand Electricity Networks Association, 2008.
71. Response to comments on appropriate productivity and input price measures to be used to update gas distributors' operating expenses. Essential Services Commission, 2007-08.
72. Advise on update of performance based regulatory plan for power distributors, including recommendations for total-factor productivity based X factors. Ontario Energy Board, 2007-08.
73. Estimate lost wage and health damages. Wolfgram and Associates, 2007.
74. Response to critique of X factor recommendations. Ontario Energy Board, 2007.
75. Review of benchmarking methods and proposed benchmarking for the pricing of unbundled copper local loop. Telecom NZ, 2007.
76. Report on the relationship between revenue decoupling and performance-based regulatory mechanisms. Massachusetts energy distribution companies, 2007.
77. Research on revenue decoupling experience in California. National Grid, 2007.
78. Report on regulatory reforms needed to facilitate demand response, advanced metering infrastructure and energy efficiency objectives. Essential Services Commission, 2007.
79. Estimate lost wage and health damages. Wolfrgram and Associates, 2007.
80. Evaluation of gas distribution construction cost trends. Essential Services Commission, 2007.
81. Appropriate productivity trends and labor inflation rates to be used to adjust operating expenses in incentive-based ratemaking. Essential Services Commission, 2007.
82. Testify in support of rate adjustment under a performance based regulation plan. Bay State Gas, 2007.
83. Report on service quality regulation and benchmarking, submitted as expert witness testimony. Detroit Edison, 2007.
84. Develop and testify in support of alternative regulation plan for gas distribution services. Client confidential at this time, 2007.
85. Evolution of energy asset management companies and outsourcing relationships. Davidson Kempner Advisers, 2007.

86. O&M partial factor productivity trends for gas distribution services. Essential Services Commission, 2006-07.

87. Principles for designing gas supply PBR plans and assessing the impact of retail gas costs. DLA Piper Rudnick, 2006-07.

88. Framework for analyzing appropriate early termination fees in competitive retail electricity markets. Essential Services Commission, 2006-07.

89. Testify in support of exogenous factor recovery of revenues lost due to declining natural gas usage. Bay State Gas, 2006.

90. Service quality benchmarking. Canadian Electricity Association, 2006.

91. Analyze natural resource and recreational damage calculations for environmental damage to trout stream. Michael, Best and Friedrich, 2006.

92. Evaluate outsourcing contract and report benchmarking Envestra's gas distribution operations and maintenance expenses. ESCOSA, 2006.

93. Report on the use of partial factor productivity trends in the updated gas access arrangement. Essential Services Commission, 2006.

94. Advise on approved X factors and total factor productivity trends in approved alternative regulation plans for electric utilities. Central Maine Power, 2006.

95. Estimate total factor productivity and input price trends power distribution industries in all Australian States and territories, Essential Services Commission, 2006.

96. Develop and testify in support of an alternative regulation plan for gas distribution services. Client wishes to remain confidential at this time, 2006.

97. Develop and testify in support of an alternative regulation plan for gas distribution services. Client wishes to remain confidential at this time, 2006.

98. Testimony on treatment of outsourcing contract costs and labor-nonlabor cost allocations. Essential Services Commission, 2005-06.

99. Incorporate lessons from incentive regulation and benchmarking overseas into newly-established regulatory framework for nation's electric utilities. Bundesnetzagentur (BNA), Bonn Germany, 2005-2006.

100. Submission to Ministerial Council on Energy related to Regulatory Rulemaking. Essential Services Commission, 2005.

101. Evaluation of early termination fee policies for energy retailers. Essential Services Commission, 2005.

102. Advise on alternative regulation strategies for gas distribution services. Client wishes to remain confidential at this time, 2005-2006.

103. Report on comprehensive framework for using performance indicators to evaluate market power abuses, efficiency gains, and the distribution of benefits to stakeholders. Essential Services Commission, 2005.

104. Evaluation of regulatory options and estimation of total factor productivity for Port of Melbourne Corporation. Essential Services Commission, 2005.

105. Evaluation of regulatory options for taxi services in Melbourne, Australia. Essential Services Commission, 2005.

106. White Paper advising government agency on regulatory reform of State's electric power industry. Department of Natural Resources Newfoundland and Labrador, 2005.

107. Review report on CAPM and differences in beta between rural and urban power distributors. Essential Services Commission, 2005.

108. Develop "incentive power" model and apply towards evaluation of regulatory options in Victoria, Australia. Essential Services Commission, 2004-2005.

109. Review report on labor price forecasts for Victoria, Australia. Essential Services Commission, 2004-2005.

110. Develop and testify in support of performance-based regulation plan. Bay State Gas, 2004-2005.

111. Review of gas regulatory framework in Ontario, Canada. Ontario Energy Board, 2004-2005.

112. Benchmarking gas distribution operations. Powerco, Vector, NGC (New Zealand), 2004.

113. Report on methodologies for updating CPI-X price controls and assemble US gas transmission pipeline data, to be used in update of price controls for gas transmission services. Comision Reguladora de Energia (Mexico), 2004-2005.

114. Benchmark comprehensive power and water utility operations. Aqualectra (Curacao, Netherlands Antilles), 2004-2005.

115. Benchmarking power distribution operations. Energex and Ergon Energy, 2004.

116. Regulatory treatment of hub and storage facilities. NICOR Gas, 2004.

117. Review and comment on proposed service quality regulation. Essential Services Commission, 2004.

118. Review and contribute to report on ring fencing policies. Essential Services Commission, Victoria Australia, 2004.

119. Estimate lost earnings in litigation case. Wolfgram and Gherardini, 2004.

120. Respond to Productivity Commission report on Gas Access Arrangements. Essential Services Commission, Victoria Australia, 2004.

121. Analysis of PBR plans for rates and service quality worldwide. Jamaica Public Service, 2004.

122. Undertake benchmarking and total factor productivity studies in support of an X factor in a performance-based regulatory plan. Jamaica Public Service, 2003-2004.

123. Evaluate incentive regulation options. Questar Gas, 2003-2004.

124. Project evaluating implementation of total factor productivity in energy utility regulation. Essential Services Commission, Victoria Australia, 2003-2005.

125. Evaluate incentive regulation reports commissioned by Australian Competition and Consumer Commission. Essential Services Commission, Victoria Australia, 2003.

126. Evaluate proposed regulatory thresholds regime. Powerco New Zealand, 2003.

127. Evaluate benchmarking methods and regulatory reform proposals. Jamaica Public Service, 2003.

128. Evaluate proposals for service quality regulation in province of Ontario. Hydro One, 2003.

129. Evaluate benchmarking methods and regulatory reform proposals. Overseas New Zealand client wishes to remain confidential at this time, 2003.

130. US-Japan power transmission benchmarking. Central Research Institute of Electric Power Industry (Japan), 2003.

131. Benchmarking power distribution operations and maintenance (O&M) costs benchmarking and O&M productivity growth. Superintendente de Electricidad (Bolivia), 2003.

132. Benchmarking gas distribution operations and maintenance expenses. ACTEW (Australia), 2003.

133. Estimate lost earnings in wrongful death case. Wolfgram and Gherardini, 2003.

134. Advise on updating incentive plan for demand-side management. Hawaiian Electric, 2003.

135. Estimate and testify in support of damages in patent infringement case, Trombetta, LLC vs. Dana Corporation and AEC. Ryan, Kromholz and Mannion, 2003.

136. Analyze service quality proposals for a natural gas distributor, recommend modifications and testify in support of recommendations. New England Gas, 2002-2003.

137. Develop a service quality incentive plan for power distributors in Queensland, Australia; the plan is to be developed through a consultative process between the companies, major customer groups, and the regulator. Queensland Competition Authority, 2002-2003.

138. Consultation on developments regarding Wisconsin Electric's "Power the Future" initiative. Fidelity Investments, 2002.

139. Confidential report on US experience with benchmarking and alternative regulation. Central Research Institute of Electric Power Industry (Japan), 2002-2003.

140. Confidential report on capital cost measurement. Central Research Institute of Electric Power Industry (Japan), 2002-2003.

141. Report on merits and feasibility of benchmarking New Zealand power distributors. United Networks, 2002.

142. Impact of gas marketing expenditures on residential gas consumption. Envestra, 2002.

143. Advise on index-based performance-based regulation plan for a power distribution utility. Client wishes to remain confidential at this time, 2002.

144. Estimate productivity trend gas distribution industry and testify in support of trend. Boston Gas, 2002-2003.

145. Gas distribution benchmarking study. TXU Australia, Envestra and Multinet, 2002.

146. Benchmarking power transmission cost. Transend, 2002.

147. Advise on the development of an incentive regulation proposal for a North American power transmission utility. Hydro One Networks, 2001-2002.

148. Application of productivity and econometric benchmarking in an update of an incentive regulation plan. Ameren UE, 2001-2002.

149. Litigation regarding violations of Unfair Trade Practices Act for Tamoxifen, Taxol, and Buspar prescription drugs. Miner, Barnhill, and Galland, P.C., 2001-2002.

150. Recommend reforms of Western Australia power market, including reforms of wholesale markets, retail markets, structure of the incumbent utility, and regulatory arrangements; work was summarized in a report to the Electricity Reform Task Force. Western Power, 2001.

151. Faculty member of Regulatory Training Seminar in Bolivia. Seminar organized by the Public Utility Research Center and sponsored by SIRESE, 2001.

152. White Paper on implementing total factor productivity measures in regulation for the Utility Distributor’s Forum. CitiPower, 2001.

153. Electronic forum on service quality incentives and research topics. Edison Electric Institute, 2001.

154. Economies of scale and scope in power services. Western Power, 2001.

155. Report evaluating the merits of alternative benchmarking methods and their application to energy distributors. Electricity Supply Association of Australia, 2001.

156. Response to report on benchmarking and incentive regulation. Client confidential at this time, 2000-2001.

157. Report on consistency of Price Determination with legislative mandates. TXU Australia, 2000-2001.

158. Develop methodology for service quality benchmarking and construction of appropriate deadbands. Massachusetts Gas and Electric Distribution Companies, 2000.

159. Advise on Performance-Based Regulation strategy, including development of a service quality incentive. BCGas, 2000.

160. Power distribution benchmarking. Queensland Competition Authority, 2000.

161. Develop and testify in support of service quality incentive. Western Resources, 2000.

162. Response to regulatory proposals for “ring fencing” operations. CitiPower, 2000.

163. Benchmarking evaluation of power distribution costs. Client name withheld, 2000.

164. Updated White Paper on Metering and Billing Competition in California. Edison Electric Institute, 2000.

165. Economies of scale and scope in power delivery and metering services. Massachusetts Utility Distribution Companies, 2000.

166. Evaluation of merger benefits. Client wishes to remain anonymous at this time, 2000.

167. Response to study on benchmarking capital spending. CitiPower, 2000.

168. Response to incentive regulation proposals of Pareto Economics in Victorian distribution price review. CitiPower, 2000.

169. Estimate scale economies in power generation, scope economies between power transmission and power generation, and implications for public policy in Western Australia. Western Power, 2000.

170. White Paper on “best practice” regulation and evaluation of price and non-price regulation of energy and water utilities in Australia, the US, and the UK. Electricity Association of New South Wales, 2000.

171. Power transmission benchmarking. Client confidential at this time, 2000.

172. Development of performance-based regulation plan for power distribution services. Texas Utilities, 2000.

173. Response to UMS benchmarking study on O&M costs. Victorian power distributors, 2000.

174. Response to Consultation Paper on Detailed Proposal for Form of the Price Control. CitiPower, 1999-2000.

175. White Paper on cost structure of power distribution. Australian power distributors (coalition contact: the Electricity Supply Association of Australia), 1999-2000.

176. White Paper on benchmarking principles and applications. Victorian power distributors, 1999-2000.

177. Service quality testimony. Hawaiian Electric, Maui Electric, and Hawaii Electric Light, 1999.

178. Faculty member of Regulatory Training Seminar in Argentina. Seminar organized by the Public Utility Research Center and sponsored by Enargas, 1999.

179. Service quality benchmarking study. Southern California Edison, 1999.

180. US-Australia performance benchmarking study. Victorian Distribution Businesses, Victoria, Australia, 1999.

181. Cost benchmarking for power delivery and customer services. Southern California Edison, 1999.

182. Development of Service Quality Incentive and Testimony in Support of Plan. Oklahoma Gas and Electric, 1999.

183. Evaluation of Intervenor Assessments of Customer Benefits in Proposed Merger. Western Resources, 1999.

184. Response to Regulator Proposals for Regulatory Methodology, Efficiency Measurement and Benefit-Sharing, and Form of Distribution Price Controls. CitiPower, Australia, 1999.

185. Response to Incentive Regulation Proposal of Australian Competition and Consumer Commission. CitiPower, Australia, 1998.

186. Report on Metering and Billing Competition in California. Edison Electric Institute, 1998-99.

187. Evaluation of Economies of Vertical Integration for Electric Utilities in Illinois. Edison Electric Institute, 1998.

188. Assessment of Cost Performance of Power Distributors in the United States and Australian state of Victoria. Victorian Power Distributors, 1998.

189. Formal Response to Regulatory Proposals for Price Cap Regulation/Development of Regulatory Options. Victorian Power Distributors, 1998.

190. Development of Service Quality Incentive and Testimony in Support of Plan. Louisville Gas and Electric/Kentucky Utilities, 1998.

191. Regulatory Support for Overall PBR Strategy. Louisville Gas and Electric/Kentucky Utilities, 1998.

192. Testimony on Impact of Brand Name Restrictions in Maine's Retail Energy Markets. Edison Electric Institute, 1998.

193. Development of Service Quality Incentive. Hawaiian Electric, 1998.

194. Regulatory Support for Comprehensive PBR Strategy and Feasibility of Retail Competition in Power Supply Services. Hawaiian Electric, 1997-98.

195. White Paper on Controlling Cross-Subsidization in Electric Utility Regulation. Edison Electric Institute, 1997-98.

196. White Paper on Cost Structure of Integrated Electric Utilities and Implications for Retail Competition. Edison Electric Institute, 1997-98.

197. Regulatory Support for a Price Cap Plan for Combination Utility. San Diego Gas and Electric, 1997-98.

198. White Paper on Price Cap Methodologies for Power Distributors in Victoria, Australia. Victorian Power Distributors, 1997.

199. Development of a Price Cap Plan for a Local Gas Distribution Utility. Atlanta Gas Light, 1997.

200. White Paper on Price Cap Regulation for Power Distribution. Edison Electric Institute, 1997.

201. Comprehensive Report on Performance-Based Regulatory Options for a Local Gas Distribution Utility. Atlanta Gas Light, 1997.

202. White Paper on Use of Electric Utility Brand Names in Competitive Markets. Edison Electric Institute, 1997.

203. Options for Price Cap Regulation for Power Distribution in Colombia. Comision Reguladora de Energía y Gas en Colombia, 1997.

204. Options for Performance-Based Regulation for Power Transmission and Stranded Cost Recovery for an Electric Utility. Client wishes to remain confidential at this time, 1997.

205. Regulatory Support for an Index-Based Incentive Plan of a Local Gas Distribution Utility. BCGas, 1997.

206. Recommendations for a service quality incentive plan. Hawaiian Electric, 1997.

207. Survey of Service Quality Incentive Plans and Assessment of Options. BCGas, 1996.

208. Regulatory Support for a Price Cap Plan. Southern California Gas, 1996.

209. Determination of service territories for newly-privatized gas distributors in Mexico. Comisión Reguladora de Energía, 1996.

210. Assessment of Regulatory Options for a Public Enterprise. United States Postal Service, 1996-97.

211. Regulatory support for a Price Cap Plan of a Local Gas Distribution Utility. Brooklyn Union Gas, 1996.

212. Development of a Price Cap Plan for the Gas Operations of a Combination Utility. Client wishes to remain confidential at this time, 1996.

213. Assessment of Options for Service Quality Incentives. Client wishes to remain confidential at this time, 1996.

214. Development of a Price Cap Plan for an Electric Utility. Client wishes to remain confidential at this time, 1996.

215. Assessment of Lessons from Natural Gas Restructuring for Electric Utilities. Client wishes to remain confidential at this time, 1996.

216. Advised on the Establishment of a Regulatory Framework for the Mexican Natural Gas Industry. Comision Reguladora de Energia, 1996.

217. White Paper on Unbundling Electric Utility Services. Edison Electric Institute, 1996.

218. Regulatory support for a Price Cap Plan of a Local Gas Distribution Utility. Boston Gas, 1995.

219. Development of a Price Cap Plan for a Local Gas Distribution Utility. Client wishes to remain confidential at this time, 1995.

220. Assessment of Incentive Regulation Options in the Context of a Proposed Restructuring of the Electric Utility Industry. Client outside of the United States wishes to remain confidential at this time, 1995.

221. Organization of a Conference on Price Cap Regulation. Edison Electric Institute, 1995.

222. Development of Regulatory Strategies Regarding the Transition to Retail Competition in the Electric Power Industry. Niagara Mohawk Power, 1995.

223. Assessment of Incentive Regulation Options in the Context of a Proposed Restructuring of the Electric Utility Industry. Alberta Power Limited, 1995.

224. Development of a Price Cap Plan for the Gas Operations of a Combination Utility. Public Service Electric and Gas, 1995.

225. Development of a Price Cap Plan for the Electric Operations of a Combination Utility. Public Service Electric and Gas, 1995.

226. White Paper on Incentive Regulation Theory and Its Application to Electric Utilities. Electric Power Research Institute, 1994-95.

227. Productivity Trends of U.S. Gas Distributors. Southern California Gas, 1994-95.

228. White Paper on Price Cap Regulation. Edison Electric Institute, 1994.

229. Regulatory Support for a Price Cap Plan. Central Maine Power, 1994.

230. Advanced Benchmarking Methods for U.S. Electric Utilities. Southern Electrical System, 1994.

231. Development of and Regulatory Support for a Price Cap Plan. Niagara Mohawk Power, 1994.

232. Competitive Price Scenarios for Power Markets in the Northeastern U.S. Niagara Mohawk Power, 1993-94.

233. Survey of Price Cap Plans in the U.S. and Abroad. Niagara Mohawk Power, 1993.

Expert Witness Testimony:

1. Before the Massachusetts Department of Public Utilities, rebuttal evidence on behalf of National Grid, 2024. Subject: performance-based regulation and performance benchmarking.
2. Before the British Columbia Utilities Commission; evidence on behalf of Fortis BC, 2024. Subject: Empirical Support for Incentive Regulation formulas.
3. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2023-24. Subject: performance-based regulation and performance benchmarking
4. Before the Ontario Energy Board, evidence on behalf of Enbridge Gas Inc., 2021-2024. Subject: plan design, policy testimony, total factor productivity and cost benchmarking in support of a multi-year, incentive ratemaking plan.
5. Before the Massachusetts Department of Public Utilities, rebuttal evidence on behalf of Eversource Electric, 2021-22. Subject: performance-based regulation and performance benchmarking.
6. Before the Massachusetts Department of Public Utilities, evidence on behalf of Berkshire Gas, 2021-2022. Subject: plan design, policy testimony, cost benchmarking in support of a performance-based regulation plan (settled in 2022).
7. Before the Massachusetts Department of Public Utilities, evidence on behalf of Eversource Electric, 2021-22. Subject: performance-based regulation and performance benchmarking.
8. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2020. Subject: rebuttal testimony on performance-based regulation and performance benchmarking
9. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2020. Subject: performance-based regulation and performance benchmarking.
10. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2019. Subject: rebuttal testimony on performance-based regulation and performance benchmarking.
11. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2018. Subject: performance-based regulation and performance benchmarking.
12. Before the Puerto Rico Energy Commission, evidence on behalf of the Puerto Rico Electric Power Authority, 2016. Subject: rebuttal testimony on cost and wage benchmarking.
13. Before the Puerto Rico Energy Commission, evidence on behalf of the Puerto Rico Electric Power Authority, 2016. Subject: cost and wage benchmarking.
14. Before the Edmonton City Council, evidence on behalf of Epcor Water and Sewer Inc., 2016. Subject: updated inflation factors in a performance-based regulation plan.
15. Before the Edmonton City Council, evidence on behalf of Epcor Water and Sewer Inc., 2016. Subject: updated inflation factors in a performance-based regulation plan.

16. Before the Wisconsin Public Service Commission, evidence on behalf of Associated Builders and Contractors of Wisconsin, 2015. Subject: assessing the merits of an expanded bidding process for the expansion of the Alliant Riverside Energy Center facility.

17. Before the Ontario Energy Board, evidence on behalf of OEB Staff, 2015. Subject: review of Custom Incentive Regulation proposal and benchmarking evidence of Toronto Hydro.

18. Before the Wisconsin Public Service Commission; evidence on behalf of Kwik Trip, 2014. Subject: surrebuttal testimony on the impact of gas extension tariffs on the development of the CNG marketplace in Wisconsin.

19. Before the Wisconsin Public Service Commission; evidence on behalf of Kwik Trip, 2014. Subject: the impact of gas extension tariffs on the development of the CNG marketplace in Wisconsin.

20. Before the Ontario Energy Board; evidence on behalf of OEB Staff, 2014: Subject: review of Customized Incentive Regulation proposal for Enbridge Gas Distribution.

21. Before the Ontario Energy Board; evidence on behalf of OEB Staff, 2013. Subject: total factor productivity estimation, cost benchmarking, and establishing incentive regulation plans for Ontario electricity distributors.

22. Before the Wisconsin Public Service Commission; evidence on behalf of Wisconsin Public Service, 2013. Subject: sur-surrebuttal testimony on the value of reliability improvements from undergrounding power lines.

23. Before the Wisconsin Public Service Commission; evidence on behalf of Wisconsin Public Service, 2013. Subject: rebuttal testimony on the value of reliability improvements from undergrounding power lines.

24. Before the Wisconsin Public Service Commission; evidence on behalf of SMART Water, 2012. Statement on appropriate opt-out policies for smart meters.

25. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of National Grid, 2010. Subject: rebuttal testimony in support of a net inflation adjustment mechanism applied to operating and maintenance expenditures.

26. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of National Grid, 2010. Subject: empirical support for a net inflation adjustment mechanism applied to operating and maintenance expenditures.

27. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2009. Subject: direct testimony on performance based regulation.

28. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2008. Subject: estimating partial factor productivity growth for O&M expenditures for natural gas distributors.

29. Before the Ontario Energy Board, 2008. Subject: appropriate values for total factor productivity-based productivity factor; benchmarking-based productivity “stretch factors;” and appropriate thresholds for capital investment modules; in an incentive regulation plan for electricity distributors in the Province.

30. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2007. Subject: direct testimony on performance based regulation.

31. Before the Circuit Court of the City of St. Louis, Missouri, Division 9, in Michele Thrash v. Freightliner *et al*, 2007. Subject: deposition testimony on estimated damages for lost income and medical treatment.

32. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2007. Subject: panel testimony on revenue decoupling and performance based regulation.

33. Before the New Zealand Commerce Commission, evidence on behalf of Telecom New Zealand, 2007. Subject: principles for price benchmarking and the merits of alternative methods of benchmarking unbundled copper local loop prices.

34. Before the Circuit Court of the City of St. Louis, Missouri, Division 13, in Anastacia McNutt v. Globe Transport, Inc *et al*, 2007. Subject: deposition testimony on estimated damages for lost income and past and future medical treatment.

35. Before the Michigan Public Service Commission; evidence on behalf of Detroit Edison, 2007. Subject: service quality regulation and benchmarking.

36. Before the Appeal Panel, South Australia, Australia; evidence on behalf of the Essential Services Commission of South Australia, 2006. Subject: the operating expenditures and outsourcing management fee of Envestra Ltd.

37. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2006. Subject: rebuttal testimony on exogenous recovery of revenues lost due to declining natural gas usage.

38. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2006. Subject: direct testimony on exogenous recovery of revenues lost due to declining natural gas usage.

39. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2006. Subject: regulatory treatment of an outsourcing contract to a related corporate party in a power distribution price determination.

40. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2005. Subject: labor and non-labor shares in operating expenditures.

41. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2005. Subject: rebuttal testimony on performance based regulation and benchmarking.

42. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2005. Subject: performance based regulation and benchmarking.

43. Before the New Zealand Commerce Commission, evidence on behalf of Vector and NGC, 2004. Benchmarking evidence for New Zealand gas distributors.

44. Before the New Zealand Commerce Commission, evidence on behalf of Powerco, 2003. Evaluation of total factor productivity and benchmarking evidence in studies undertaken for the Commission.

45. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Boston Gas, 2003. Subject: rebuttal testimony on performance based regulation, total factor productivity measurement and benchmarking

46. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Boston Gas, 2003. Subject: performance based regulation, total factor productivity measurement and benchmarking

47. Before the US District Court for the Western District of Wisconsin, Trombetta, LLC vs. Dana Corporation and AEC, 2003. Subject: estimate damages in solenoid patent infringement case.

48. Before the Rhode Island Public Utilities Commission: evidence on behalf of New England Gas, 2003. Subject: direct testimony on alternative service quality regulation proposals.

49. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2001. Subject: reply to surrebuttal testimony in support of service quality incentive plan.

50. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2000. Subject: rebuttal testimony in support of service quality incentive plan.

51. Before the Supreme Court of Victoria, Australia; evidence on behalf of TXU Australia, 2000. Subject: Whether the regulator's price determination complied with legal mandates to use price-based incentive regulation.

52. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2000. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

53. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Massachusetts gas and electric distribution companies, 2000. Subject: Service quality benchmarking.

54. Before the Hawaii Public Service Commission; evidence on behalf of Hawaiian Electric, 1999. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

55. Before the Oklahoma Corporation Commission; evidence on behalf of Oklahoma Gas and Electric, 1999. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

56. Before the Kentucky Public Service Commission; evidence on behalf of Louisville Gas and Electric and Kentucky Utilities, 1998. Subject: Rebuttal testimony in support of service quality incentive plan and benefits of companies' regulatory proposal to low-income customers.

57. Before the Kentucky Public Service Commission; evidence on behalf of Louisville Gas and Electric and Kentucky Utilities, 1998. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

58. Before the Maine Public Utilities Commission, evidence on behalf of the Edison Electric Institute, 1998. Subject: Merits of allowing utility companies to use their brand names in competitive retail energy markets.

59. Before the California Public Utilities Commission, evidence on behalf of the Edison Electric Institute, 1997. Subject: Merits of allowing utility companies to use their brand names in competitive retail energy markets.

Publications:

1. *The Price Cap Designers Handbook* (with M. N. Lowry), Edison Electric Institute, 1995.
2. "The Treatment of Z Factors in Price Cap Plans" (with Mark Newton Lowry), *Applied Economics Letters*, 2: 1995.
3. "Forecasting Productivity Trends of Natural Gas Distributors" (with Mark Newton Lowry), *AGA Forecasting Review*, March 1996.
4. *Performance-Based Regulation for Electric Utilities: The State of the Art and Directions for Further Research* (with Mark Newton Lowry), Palo Alto: Electric Power Research Institute, 1996.
5. *Developing Unbundled Electric Power Service Offerings: Case Studies of Methods and Issues* (with Laurence Kirsch), Washington: Edison Electric Institute, 1996.
6. *"*A Theoretical Model of Spillovers Through Labor Recruitment", *International Economic Journal*, Autumn 1997.
7. *Branding Electric Utility Products: Analysis and Experience in Related Industries* (with Mark Newton Lowry and David Hovde), Washington: Edison Electric Institute, 1997.
8. "The Branding Benefit", *Electric Perspectives*, November 1997.
9. *Price Cap Regulation for Power Distribution* (with Mark Newton Lowry), Washington: Edison Electric Institute, 1998.
10. *Controlling for Cross-Subsidization in Electric Utility Regulation* (with Mark Meitzen and Mark Netwon Lowry), Washington: Edison Electric Institute, 1998.
11. "Price Caps for Distribution Service: Do They Make Sense?", *Edison Times*, December 1998 (with Eric Ackerman and Mark Newton Lowry).
12. *Economies of Scale and Scope in Power Distribution* (with Mark Newton Lowry), Washington: Edison Electric Institute, 1999.
13. *Competition for Metering, Billing and Information Services: The Experience in California So Far*, Edison Electric Institute, 1999.
14. *Third Party Metering, Billing and Information Services: Further Evidence from California*, Edison Electric Institute, 2000.
15. "Performance Based Regulation of Energy Utilities" (with Mark Newton Lowry), *Energy Law Journal*, 2002
16. "Performance Based Regulation and Business Strategy" (with Mark Newton Lowry), *Natural Gas*, 2003.
17. "Performance Based Regulation and Energy Utility Business Strategy" (with Mark Newton Lowry), *Natural Gas and Electric Power Industries Analysis 2003*, Financial Communications, Houston, 2003
18. "Price Control Regulation in North America: Role of Indexing and Benchmarking," (with M.N. Lowry and L. Getachew), *Proceedings of Market Design Conference*, Stockholm, Sweden, 2003.
19. "Performance Based Regulation Developments for Natural Gas Utilities" (with Mark Newton Lowry), *Natural Gas and Electricity*, 2004.
20. "Incentive Power and the Design of Regulatory Regimes," *Network*, December 2005.

21. “Alternative Regulation for Electric Utilities” (with Mark Newton Lowry), *Electricity Journal*, June 2006.

22. ”Performance Indicators and Price Monitoring: Assessing Market Power,” *Network*, March 2007.

23. “Incentive Regulation in North American Energy Markets” *Energy Law and Policy*, Carswell Publishing, Toronto, Canada, 2009.

24. “Regulatory Reform in Ontario: Successes, Shortcomings and Unfinished Business” *Public Utilities Fortnightly*, November 2009

25. “An Update to Keystone XL Development,” *CERI Crude Oil Report*, September 2015

26. “Mexico Natural Gas Reform,” *Geopolitics of Energy*, January-February 2016

27. “Clean Energy Policy in the U.S.” *Geopolitics of Energy*, July 20616.

28. “The Energy Policy Outlook Under President Trump,” *Geopolitics of Energy*, November-December 2016.

29. “Electricity Security, Renewables, and the South Australia Power Outages,” *Geopolitics of Energy*, April-May 2017.

30. “Prospects for Nuclear Power in the U.S.,” *Geopolitics of Energy*, August 2017.

31. “The Past and Future of the X Factor in Performance-Based Regulation,” *Geopolitics of Energy*, February 2019

32. “The Past and Future of the X Factor in Performance-Based Regulation,” *The Electricity Journal*, April 2019

Presentations at Seminars and Professional Meetings:

1. Department of Energy/NARUC, Orlando, FL, 1995.
2. Illinois Commerce Commission and the Center for Regulatory Studies, St. Charles, IL, 1995.
3. Regulatory Studies Program, NARUC/Michigan State University, East Lansing, MI, 1995.
4. Marketing Conference, Edison Electric Institute, Chicago, IL, 1997.
5. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 1997.
6. Code of Conduct Conference, Denver, CO, 1997.
7. Code of Conduct Conference, Denver, CO, 1998.
8. Forum on Price Cap Regulation for Power Distribution. Melbourne, Australia, 1998.
9. Conference on Competition and Regulatory Reform in Hawaii. Honolulu, HI, 1998
10. Alternative Approaches Towards Price Cap Regulation. Melbourne, Australia, 1998.
11. Economics Meetings, Edison Electric Institute. Charlotte, NC, 1998.
12. Metering, Billing and Information Services Policy Convention, EEI, Chicago, IL, 1999.
13. Electricity Deregulation Conference. Vail, CO, 1999.
14. PURC Regulatory Training Seminar for Natural Gas Policy, Buenos Aires, Argentina, 1999.
15. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2000.
16. Seminar on Theory and Practice of Economic Regulation, Sydney, Australia, 2000.
17. Power Delivery Reliability Conference. Denver, CO, 2000.
18. Performance-Based Regulation Conference. Chicago, IL, 2000.
19. Regulatory Studies Program, NARUC/Michigan State University, East Lansing, MI, 2000.

20. Performance-Based Ratemaking Conference, Denver, CO 2000.
21. Energy Forum, Institute of Public Affairs, Melbourne, Australia, 2000.
22. Chamber of Commerce and Industry, Perth, Australia, 2001.
23. Energy Regulation Conference, Melbourne, Australia, 2001.
24. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 2001.
25. PURC Regulatory Training Seminar, La Paz, Bolivia, 2001.
26. Performance-Based Regulation Conference, Denver, CO, 2001.
27. Cost Structure of Energy Networks, Sydney, Australia, 2002.
28. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 2002.
29. Performance-Based Ratemaking Conference, Denver, CO 2002.
30. How to Regulate Electricity Lines Companies?, New Zealand Institute for the Study of Competition and Regulation, Wellington, New Zealand, 2003
31. Public Utility Regulation Seminar: Tariff Design and Incentives, Acapulco, Mexico, 2003
32. Rates and Regulation Meeting: Southeastern Electric Exchange, Williamsburg, VA, 2003.
33. Workshop on Service Quality Regulation in Ontario, Toronto, ON 2003.
34. Joint Canadian Electricity Association Distribution Council and Customer Council Meeting, Halifax, Nova Scotia, 2004.
35. Asia-Pacific Productivity Conference, Brisbane, Australia, 2004. [invitation, paper submitted]
36. Workshop on Productivity Measurement, Melbourne Australia, 2005.
37. Utility Regulators Forum, Canberra Australia, 2005.
38. CAMPUT Energy Regulation Course, Kingston Canada, 2006.
39. Performance Based Regulation Seminar, Toronto Canada, 2006.
40. Performance Benchmarking for Energy Utilities, Arlington, Virginia, 2006.
41. Performance Benchmarking for Energy Utilities, Seattle, Washington, 2007.
42. Alternative Regulation Seminar, Boston, Massachusetts, 2007.
43. CAMPUT Energy Regulation Course, Kingston Canada, 2007.
44. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2008.
45. Performance Benchmarking for Energy Utilities, Denver, Colorado, 2008.
46. Alternative Regulation Seminar, Toronto, Canada, 2008.
47. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2008.
48. CAMPUT Energy Regulation Course, Kingston Canada, 2008.
49. Performance Benchmarking for Energy Utilities, Chicago, IL, 2008.
50. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2009.
51. Alternative Regulation Seminar, Boston, MA, 2009.
52. CAMPUT Energy Regulation Course, Kingston Canada, 2009.
53. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2010.
54. Alternative Regulation Seminar, Boston, MA, 2010.
55. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2010.
56. CAMPUT Energy Regulation Course, Kingston Canada, 2010.
57. Alternative Regulation Seminar, Toronto Canada 2010.
58. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2011.
59. Alternative Regulation Seminar, Philadelphia PA, 2011.
60. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2012.
61. Alternative Regulation Seminar, Chicago, IL, 2012.
62. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2013.
63. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2013.
64. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2014.
65. Alternative Regulation Seminar, Chicago, 2014.

66. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2014.
67. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2015.
68. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2015.
69. CERI Oil and Gas Conference, Calgary, Canada. 2015.
70. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2016.
71. Latin American Natural Gas Conference, Naturgas, Cartegena, Colombia, 2016.
72. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2016.
73. CERI Electricity Conference, Calgary, Canada, 2016.
74. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2017.
75. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2018.
76. Florida Infrastructure Conference, Gainesville, FL, 2018.
77. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2018.
78. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2019
79. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2019.
80. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2020.

Abbas Lakha, CPA, CA

Associate Partner
Consulting Services

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Career summary

Ernst & Young LLP
2009 – 2013
2015 – Present

Toronto Hydro
2013 – 2015

Industry Expertise

Energy services/ Power and Utilities

Education

Honours Bachelor of Business Administration, Schulich School of Business, York University

Certification(s)

CPA, CA

Community Activities(s)

Director, Canadian Charity
2017 - present

Summary

Abbas is an Associate Partner with the Consulting Services group in Toronto and has been with EY since 2009, with a gap of two years in industry within the Power and Utilities Sector. He has gained IFRS US GAAP, and regulatory accounting experience by working with public and private companies in a variety of industries, specifically in power and utilities.

Abbas has also been involved with advising companies on complex accounting issues, developing capex and depreciation policies, as well as assisting with regulatory filings and queries. Further, Abbas has significant experience in the regulatory landscape, assisting large utilities with amalgamations, process improvement, risk mitigation, harmonization of policies and processes and the understanding of regulatory implications.

Relevant Professional Experience

- **Consulting Services:**

  Various Gas, Water and Electricity Utilities:
  - Lead a team of individuals working with a large P&U client on a transformation initiative as part of an integration effort. This included a review accounting policy, harmonization of finance and business processes, documentation of processes and identification of automation and process improvement opportunities
  - Assisted management in identifying key areas of focus and priority for the customer care team in an effort to improve the customer experience
  - Conducted several process reviews across various areas of the business including the collections and customer process
  - Lead a team to assist the utility in harmonizing and aligning management reporting between legacy entities. This included the implementation of Power BI and an Azure data model in an effort to create a source of truth for the finance department
  - Assisted management in determining the regulatory impact of alignment decisions and providing a tracking mechanism
  - Assisted management in identifying efficiency opportunities including the use of automation in core finance processes
  - Assisted management in the review of cost allocations between their unregulated and regulated business. This included a formal study of costs allocation and the documentation of a harmonized approach for the amalgamated entity
  - Led a team of individuals to undertake an overhead capitalization study across serval clients resulting in a report documenting management's approach to overhead capitalization
  - Assisted management in understanding the implications to regulatory accounting of changes in various accounting policies and processes through the establishment of a deferral account
  - Assisted with the review of the business support team, including a process, FTE and technology review outlining key process gaps and improvements
  - Lead a team to understand and document legacy methodologies in relation to the unbilled revenue model and document observations with respect to variances, assumptions and gaps within the model
  - Provided recommendations to assist the large utility in better tracking its assets, and creating a formidable capex strategy
  - Assisting the company in understanding and applying reasonable depreciation policies in line with regulatory requirements
  - Lead a team of individuals in a review of the unbilled revenue methodology, including interactions and interviews with regulatory staff
  - Worked with the audit committee to update the COSO framework and the governance structure of the internal audit group
  - Responsible for assisting with segments of multi year regulatory filings and rate case approvals
  - Responsible for evaluating and determining process gaps in the RRR process and filing and providing relevant recommendations to leadership

- Responding for providing reports relating to various business processes identifying opportunities to enhance the control environment and create efficiencies in serval processes.

- **Shareholder owned Electricity Generator, Gas, Water and Electricity Utility**
  - Led the audit of a large multi-billion-dollar power and utilities company, dealing with complex revenue transactions, business acquisitions and several other key accounting considerations
  - Responsible for understanding and dealing with regulatory issues across several US states, including but not limited to: Georgia, Arizona, California and New Hampshire.

Andrew Grainger, FCPA, FCGA
Partner
Business Consulting

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Industry lines
Power and Utilities
Nuclear
Oil & Gas

Education
University of Calgary
Bachelor of Accounting Science

Certification(s)
Fellow Chartered Professional Accountant (FCPA), Fellow Certified General Accountant (FCGA)

Professional experience summary
Andrew Grainger is a Partner in the Business Consulting practice of EY LLP and is the Canadian Power & Utility Consulting leader. He is responsible for managing and developing a diverse and skilled group of business advisors as well as securing new business with a number of market leading companies across a Canada.

Andrew has 25 years of experience working with clients in the Power & Utilities industry and has extensive experience with strategic, system implementation and integration projects, project management, and business process transformation and reengineering initiatives across Finance, IT, Supply Chain, and other operations.

Engagement experience
- Andrew is the coordinating partner for a large natural gas utility client and oversees the delivery of numerous engagements throughout the utility's operations, including the development of target operating models in Operations, Customer Care, Engineering, Storage and Transmission, Distribution Operations, and Finance.
- Andrew is the Global Client Service Partner for a large Electric Transmission & Distribution Company, and responsible for the coordination of our work across multiple areas of the organization, including Strategy, Customer Experience, Finance, as well as working with the COO and his VP's to develop and execute on their overall strategy for the Energy Transition and the role their respective groups are responsible for in order to enable that transition.
- Andrew is the Global Client Service Partner for a large Electric Distribution Company, and responsible for the management of numerous engagement teams, including the large systems integration of the ERP systems from four legacy utilities joined through merger and acquisition, in to one system. He is working closely with senior management as part of the Executive Steering committee to identify project risks and opportunities to drive business value and efficiencies as a result of the ERP convergence and provide ongoing support to senior management throughout the project.
- Andrew is the lead partner working with a large P&U client on a Finance Transformation initiative as part of an integration effort. He is leading a team working with senior management to review accounting policies, business processes, and system needs to develop a roadmap toward an integrated solution, and then execute on that roadmap over the next ten months.
- For a large P&U client, Andrew is the engagement partner leading a team to provide an ongoing assessment as to the current and emerging issues and risks that may impede the on-time / on-budget / on-scope delivery of a custom development Customer Information System modernization project. The team is working alongside the PMO to provide recommendations and assist management with mitigating high-priority issues and risk identified, provide assessment, maintenance, scheduling and tracking of the Project Plan, including daily updates based on Service Provider and the client's progress. The team is also providing ongoing support to management in relation to business case realization.
- Andrew is the engagement partner for a large scale P&U client, leading a team to provide an ongoing assessment as to the current and emerging issues and risks that may impede the on-time / on-budget / on-scope delivery of a Maximo and ClickSoftware implementation project. The team is working with management to provide recommendations and assist management with mitigating high-priority issues and risk identified. Andrew sits on the Executive Steering Committee to provide ongoing support to senior management throughout the project.
- For a Multi-service utility in Ontario, serving 360,000 electric & water customers, Andy was the QA partner working with the team to provide oversight for the design, development and delivery of a role-based, blended curriculum for an Oracle CC&B, MTM, and MDMR

implementation. The program included: needs analysis, user task analysis, web-based and instructor-led curriculum design, train-the-trainer, learning management system set-up, and business process refinement and knowledge transfer planning.

- For the largest Nuclear Power Generation facility in North America, Andrew served as the lead partner to advise senior management on select strategic initiatives to streamline processes and reduce costs. The assessments to date have covered areas in finance, supply chain and commercial services, IT project management, application rationalization, and throughout operational functions of the company. This also included project reviews to provide senior management with an independent evaluation of selected critical projects.
- For a large natural gas utility, Andrew oversaw a team working with the finance and regulatory team to provide an assessment of the capitalization policies for indirect overheads. This engagement included the preparation of a report that was filed with the utilities regulator as evidence to support the reasonability of their approach.
- Andrew was the engagement partner for a procurement transformation program at a large nuclear power generation facility. Scope included integrated work management, maintenance and engineering, redesigning of procurement processes, and improving management of MRO and capital spares inventory
- For a large natural gas transmission, distribution and storage company, Andrew was the engagement partner advising the company on carving out business processes and functions for the regulated portion of their business, in order to address regulatory requirements. This involved an in-depth review of their current business process in order to determine and develop a roadmap for the necessary changes required to business process, management reporting and system requirements to enable them to capture the appropriate information in an efficient manner and produce the required information on an ongoing basis.
- Andrew led a review of the AP shared services function for a large P&U client. He led a team working with senior management to perform a current state assessment of the business processes, identified gaps, manual workarounds and compensating controls currently being used, to design a future state process that will enable them to take advantage of automation technology. The future state model streamlined the business processes, reducing the need for manual intervention and workarounds, as well as increasing control effectiveness and reducing the risk of manual error.
- For a large P&U company that was experiencing a period of unprecedented growth in its regulated business, Andrew was the engagement partner leading an assessment of the Plan, Budget, and Forecast process. As the company was undertaking some of the largest capital expansion projects in its history, Andrew led the project team to assist the organization with enhancing their PBF process to allow them to balance this growth with their regulatory requirements, implement changes to their process and tools to enable them to closely monitor their budgets, and prepare driver based forecasts to better support decision-making. The enhanced process provided increased the transparency in its budgeting and forecasting processes, as well as increased the value that the Planning and Forecasting team delivers to the organization.
- Andrew was the Partner that oversaw an Enterprise Resource Planning (ERP) Needs Assessment and Scoping for an LDC in Southwestern Ontario to identify opportunities to create business value based on their strategic and operational priorities, and on industry leading practices. Defined ERP solution architecture options based on the capabilities required by the LDC to execute on the benefits opportunities, including non-ERP components. Analyzed and compared the ERP solution architecture options based on the differential business value they enabled, and their corresponding one-time implementation costs, ongoing operating costs, execution risk and ongoing operating risk factors, a robust, rigorous process including scenario and sensitivity analyses and leveraging our understanding of cost and risk factors specifically in the LDC's environment and based on our industry-specific knowledge capital and fact bases.
- Power & Utilities company, Fleet policy integration - Led the team working with fleet management to review the fleet policies (incl. vehicle assignment and fit for purpose) and supported the development and implementation of a harmonized policy.
- Power & Utilities company, Garage strategy Led the team working with fleet management to perform a current state assessment of the garage operations in the two legacy companies and, through detailed financial analysis and productivity analysis, supported the design of the future state integrated operating model for the garage operations.

- Power & Utilities company, Fleet support strategy - Led the team working with fleet management to perform a current state assessment of the fleet support function in the two legacy companies and, through detailed financial analysis and productivity analysis, supported the design of the future state integrated operating model for the fleet support operations.
- Power & Utilities company, Auto Taxable Benefit -Led the team working with fleet management and HR / payroll to perform a current state assessment of the two legacy companies' auto taxable benefit processes and identified gaps against the CRA policy to design a future state integrated process with greater CRA compliance and an improved information flow to HR / payroll
- Power & Utilities company, Content Management - Leading a team to provide an ongoing assessment of the current and emerging issues and risks that may delay the delivery of the roll out of a content management program (storage and delivery). The team is working alongside the PMO to provide recommendations and assist management with mitigating high-priority issues and risks identified and provide assessment from an organizational change management, IT and operational perspective.
- Power & Utilities company, Engineering wavespace™ session- Conducted a virtual wavespace™ session designed to help the Engineering and Storage and Transmission team to obtain an overview of future industry trends, align and recalibrate near-term strategic priorities and craft a roadmap.
- Power & Utilities company, organizational design for Finance, and Customer Care & Sales functional areas - Supported and facilitated the design of the amalgamated Finance and Customer Care & Sales functions. The team developed high level design of the amalgamated organization for these functions. The engagement also included detailed organization design and talent selection, and development and execution of the people transition strategy and plan for Finance.
- Power & Utilities company, rapid synergy assessment - The engagement involved the high-level identification of synergies through executive leadership interviews, headcount and productivity benchmarking and examination of corporate reports.
- Power & Utilities company, Distribution Operations integration projects - Supported various engagements within Operations to design of the future state operating models for Field Execution, Planning and Dispatch and Customer Connection. EY facilitated several workshops with Operations Teams and Leadership, and developed a decision-making approach to evaluate current state operating models and supported detailed analysis.
- Natural gas company, Distribution Operations wavespace™ session - Conducted an interactive wavespace™ session to provide them with an overview of the global trends in the natural gas industry, deep dive and demonstrations on the innovations in the industry to develop the Distribution Operations long-term strategic roadmap
- Power & Utilities company, Customer Care & Sales operating model assessment - Supported the client with the design of the amalgamated future state operating model for the function. The team conducted site visit, analyzed key metrics data, performed costing analysis and evaluated business and financial benefits to develop recommendations on the operating model
- Power & Utilities company, Integration Management office advisory - Reviewed and assessed the reasonableness of identified synergies and overall targets. Advised the Integration Management Office ("IMO") on leading practices for interdependency management, performance measurement, key performance metrics and executive and operational dashboarding

Years of Experience
Professional start date: March 2012

ICF start date: July 2016

Education
M.A., International Economics and Energy, Resources & Environment, Johns Hopkins School of Advanced International Studies, 2016

B.A., International Studies and Psychology, Johns Hopkins University, 2011

Andrew Griffith

Energy Markets Manager

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Andrew Griffith is an energy markets manager in ICF's natural gas and utilities advisory services group. He has more than six years or experience in the energy field.

Mr. Griffith provides in-depth analytical and regulatory support for natural gas and joint utilities on issues related to policy-driven electrification and decarbonization policy, commodity supply planning, peak day infrastructure requirements, and storage utilization. Mr. Griffith has participated in numerous studies forecasting natural gas market developments in North America, analyzing emissions and decarbonization trends, analyzing sector resilience and capacity, and projecting long-term natural gas infrastructure spending. Mr. Griffith has presented in both public and private forums on these topics.

Mr. Griffith also provides assessments of the value of new natural gas pipeline and storage assets to utilities and ratepayers. He has worked extensively on Canadian natural gas market and regulatory issues.

Mr. Griffith holds an M.A. in International Economics and Energy, Resources & Environment from the Johns Hopkins School of Advanced International Studies and a B.A. in International Studies and Psychology from Johns Hopkins University.

Mr. Griffith has assisted on testimony in regulatory and legal proceedings related to natural gas distribution company pipeline contracting, infrastructure capacity requirements, natural gas storage economics, and pipeline facility expansion economics.

Project Experience

Natural gas storage valuation for asset owner, 2019 & 2022. For a confidential client, Mr. Griffith valued a portfolio of natural gas assets in two different regional gas markets for the owner of the assets. Implemented changes to the ICF gas storage model to add more realistic daily price volatility into the model.

Natural gas supply portfolio analysis, 2019-2021, Summit Natural Gas of Maine. For Summit Natural Gas of Maine, Mr. Griffith was a consultant who quantitatively and qualitatively compared pipeline supply and LNG import supply options for Summit Utilities during a regulatory proceeding to determine the prudence of contracting for pipeline capacity on the Algonquin Gas Transmission Atlantic Bridge project. Provided regulatory approval and legal testimony support for the resulting supply contracting.

Filed as an expert report by Michael Sloan: *Request for Approvals and Findings Related to Atlantic Bridge Project.* Summit Natural Gas of Maine, Inc. Maine Public Utilities Commission. Docket No. 2019-00185.

New York Natural Gas Planning Study, 2019-2021. For a confidential client, Mr. Griffith was the lead analyst assessing the current state of New York natural gas markets. Provided an assessment of regions in New York with constrained infrastructure and expected demand growth after gathering information from New York's gas utilities, interstate pipelines, and other sources. Modelled the cost of various policy scenarios for achieving New York's emissions goals under the CLCPA.

Natural gas storage buy-side review, 2021. For a confidential client, Mr. Griffith led a study that valued a portfolio of U.S. Gulf Coast natural gas assets. Assessed the physical characteristics, competitive landscape, market growth opportunities, and provided rate forecast scenarios.

IRP Jurisdictional Review, Enbridge, 2020. For Enbridge, Mr. Griffith compared the regulatory environments in Ontario and New York to assess the differences in non-pipeline solutions, demand side management, infrastructure requirements planning, and other natural gas market planning.

Natural gas storage valuation for asset owner, 2020. For a confidential client, Mr. Griffith led a study to value a portfolio of natural gas assets in four different North American gas markets for the owner of the assets. Assessed all aspects of each market that effect gas prices and access to natural gas production and demand sources including infrastructure constraints and project development.

Climate Change Risk Assessment Report, 2021, 2020 & 2018, Devon Energy. For Devon Energy, Mr. Griffith led an analysis of expected commodity prices, demand levels, and production potential in two reference scenarios and two sustainable development scenarios in order to assess the resilience and profitability of Devon's production portfolio. The results were published in public reports for Devon's investors.

North American Midstream Infrastructure - A Near Term Update Through 2025, INGAA, ICF, 2020. For INGAA, Mr. Griffith was a consultant who reported on the amount of oil & gas infrastructure development and demand growth expected through 2025 in light of the COVID-19 pandemic.

Impact of Changing Supply Dynamics on the Ontario Natural Gas Market, Enbridge, 2019. Mr. Griffith was a consultant contributing to the analysis in the expert report, "Impact of Changing Supply Dynamics on the Ontario Natural Gas Market", which was authored by Michael Sloan and Srirama Palagummi and submitted on behalf of Enbridge Gas Limited, before the Ontario Energy Board in Case EB-2019-0159 in July 2019.

South Carolina natural gas transportation and supply cost guidance, 2019, South Carolina State House. For the South Carolina State House, Mr. Griffith was the lead natural gas consultant on a study that researched, summarized, and evaluated gas source costs and transportation costs for future gas-fired power generation for the state of South Carolina. Assessed pipeline constraints and idenitfied pipeline supply options by communicating with the interstate pipelines that serve South Carolina and conducting an independent assessment.

Natural gas storage valuation for a utility, 2019, Heritage Natural Gas. For Heritage Natural Gas, Mr. Griffith valued natural gas storage capacity and varying levels of deliverability for a gas utility. Accounted for the client's projected demand and portfolio of supply and transportation contracts in order to determine their optimal level of storage capacity.

Development of a methane emissions calculator, 2019, NYC Office of Sustainability. For the New York City Office of Sustainablity, Mr. Griffith designed and built a tool for calculating lifecycle methane emissions for use by cities and local distribution companies.

North American Midstream Infrastructure Investment through 2035, INGAA, ICF, 2018. For the Interestate Natural Gas Association of America, Mr. Griffith was a consultant who analyzed the amount of oil & gas infrastructure development possible in North America through 2035 for two different scenarios using ICF's Midstream Infrastructure Report (MIR) and other modeling tools. The study assessed capital expenditures in base case and rising cost scenarios and the resulting economic consequences of oil and gas infrastructure development.

Natural gas supply and demand forecast, ISO-NE, 2018. For the Independent System Operator of New England, Mr. Griffith was a consultant on a study that reported on the expected annual, winter, summer, and peak demand for natural gas in New England along with potential sources of gas supply.

Impact of Dawn LTFP Service on Western Canadian Markets, Union Gas Limited (now Enbridge), 2017. For Union Gas Limited, Mr. Griffith was a consultant who analyzed the impact of the TC Energy Dawn Long-Term Fixed Price service on Western Canadian producers and Ontario markets by projecting the change in prices at Dawn hub.

U.S. Oil and Gas Infrastructure Investment through 2035, API, ICF, 2017. For the American Petroleum Institute, Mr. Griffith was a constulant who analyzed the amount of oil & gas infrastructure development possible in U.S. through 2035 for two different scenarios using ICF's Midstream Infrastructure Report (MIR) and other modeling tools. The study assessed capital expenditures and the resulting economic consequences of oil and gas infrastructure development.

Supply Curve Development, Environmental Proctection Agency, 2017. For the U.S. Environmental Protection Agency, Mr. Griffith was a consultant who developed supply curves for an EPA project using the EIA Annual Energy Outlook and ICF's Gas Market Model.

Gas Market Constraint Modeling, Exelon, 2017. For Exelon, Mr. Griffith was a consultant who researched and modelled the power and gas market capacity in a specific geogprahic region under various supply and weather scenarios. The modelling included forecasting design day natural gas demand natural gas infrastructure requirements.

Gas Supply Cost Assessment, AECI, 2017. For AECI, Mr. Griffith was a consultant who assessed the cost of supplies of natural gas under various scenarios and calculated the cost of transporting gas along various pipeline routes. Helped determine the value of new pipeline capacity between the Rockies Express Pipeline and the St. Louis, Missouri area.

Decarbonization Risk Modelling, Union Gas Limited (now Enbridge), 2017. For Union Gas Limited, Mr. Griffith was a consultant who modelled the risk to natural gas assets by decarbonization efforts until the year 2050.

Natural Gas Storage Valuation, Union Gas Limited (now Enbridge), 2017. For Union Gas Liminted, Mr. Griffith was a consultant who modelled the value of geogprahic region's natural gas storage using basis differentials and other key variables.

Regional and North American Market Analysis, Enbridge, 2016. For Enbridge, Mr. Griffith was a consultant who analyzed the current and future market for natural gas, focusing on specific regions of interest.

Economic Impacts of the Port Arthur Liquefaction Project, Sempra, 2016. For Sempra, Mr. Griffith was an analyst that assisted in writing a report on the economic effects of the proposed Port Arthur LNG export facility as part of a U.S. Department of Energy permit application.

Demand Elasticity Determination, Environmental Proctection Agency, 2016. For the U.S. Environmental Protection Agency, Mr. Griffith was a consultant who used projected demand and price levels to determine the future elasticity of demand for multiple regions, seasons, and years in the future.

Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short- and Near-Term Electric Generation Needs, ISO New England, 2016. For the Indepdent System Operator of New England, Mr. Griffith was an analyst who assisted in providing a summary of the current natural gas pipeline infrastructure in New England and an assessment of the potential future development of additional pipelines in the region.

Market Analysis, Propane Education and Research Council (PERC), 2016. For the Propane Education and Research Council, Mr. Griffith was an analyst who assisted in developing a state-by-state analysis of the markets for propane in all sectors. Compared internal propane import volume data with external sources in order to find disparities.

Market and Infrastructure Reliability Analysis, DTE Energy, 2016. For DTE Energy, Mr. Griffith was an analyst who assessed the ability of the current natural gas infrastructure to meet demand and analyzed potential vulnerabilities in the infrastructure.

Infrastructure Vulerability Analysis, U.S. Department of Energy (DOE), 2016. For the U.S. Department of Energy, Mr. Griffith was an analyst who collaborated on a report on areas of vulnerability in the natural gas infrastructure in the U.S. with the office of Energy Policy and Systems Analysis (EPSA).

Subscription Projects

Gas Market Compass, Numerous Clients. Assists in the production of ICF's quarterly-produced base cases for the North American natural gas markets.

Detailed Production Report, Numerous Clients. Assists in the production of this service that provides ICF's projection of gas, oil, and natural gas liquid production over time.

Midstream Infrastructure Report, Numerous Clients. Assists in the production of this product that assesses the amount of midstream infrastructure, including gas pipeline capacity that is likely to be built in markets throughout North America over the next 20 years.

Select Publications and Presentations

Griffith, A. & Milligan, P. (2021) Presented to the Association of Energy Engineers – Oklahoma. *ERCOT February 2021 Blackout: Overview and Open Questions*. Fairfax, VA: ICF.

Petak, K., Manik, J., A., Griffith, A. (2018) American Petroleum Institute and ICF. *North America Midstream Infrastructure through 2035: Significant Development Continues*. Fairfax, VA: The INGAA Foundation, Inc.

Petak, K., Vidas, H. Manik, J., Palagummi, S., Ciatto, A., Griffith, A. (2017) American Petroleum Institute and ICF. *U.S. Oil and Gas Infrastructure Investment Through 2035*. Washington, DC: American Petroleum Institute.

International Trade Administration (2015). *2015 Top Markets Report – Renewable Fuels: A Market Assessment Tool for U.S. Exporters*. Washington, DC: U.S. Department of Commerce.

Employment History

ICF. Senior Energy Markets Consultant. Fairfax, VA. 2016 – Present.
Swiss Re. Climate Consultant. Washington, DC. 2014-2015.
U.S. International Trade Administration. Intern. Washington, DC. 2014.
Accenture. Senior Analyst. Washington, DC. 2012-2014.
U.S. Department of State. Intern. Brussels, Belgium. 2011.
RBI Strategies and Research. Intern. Denver, CO. 2008-2009.

Michael Sloan

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EXPERIENCE OVERVIEW

Michael Sloan is the Managing Director for ICF's Natural Gas and Liquids Advisory Services Group. He has more than 40 years of experience in the energy field.

Mr. Sloan provides in-depth analytical and regulatory support for natural gas utilities on issues related to policy-driven electrification and decarbonization policy, the potential for non-pipeline solutions to meet natural gas demand growth, natural gas utility avoided costs, and the value of natural gas demand side management (DSM). He also provides assessments of the value of new natural gas pipeline and storage assets to utilities and ratepayers. Mr. Sloan has worked extensively on Canadian natural gas market and regulatory issues.

Mr. Sloan has also provided market analytics and regulatory support for the propane industry since 2004. In addition to his work evaluating propane market trends and the economic impacts of the propane industry, he is currently focusing on the potential impacts of climate change policies on the industry.

Mr. Sloan is a frequent speaker at natural gas and propane conferences and association board meetings, and has submitted testimony in more than 40 regulatory and legal proceedings related to natural gas distribution company non-pipeline solutions, natural gas avoided costs, natural gas storage market power, natural gas storage economics, natural gas storage land owner issues, pipeline facility expansion economics, propane pricing power and other issues.

Years of Experience

- 40 years of experience in natural gas and liquids market and policy analysis

Education

- B.A., Economics, Policy Studies/Operations Research, Dartmouth College, Hanover, NH.

PROJECT EXPERIENCE

Selected Natural Gas Industry Analysis and Regulatory Support Projects

Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals", March 2020. For Washington Gas and AltaGas Mr. Sloan led a major study to evaluate the potential for a major natural gas distribution company to reach net zero carbon emissions by 2050.

2018 Potential for Infrastructure IRP to Avoid Natural Gas Distribution Facilities Investments. March 2018. For Union Gas and Enbridge Gas in Ontario, Mr. Sloan led a major study to evaluate the potential for an integrated planning process to reduce the need for new distribution company infrastructure by implementing targeted DSM programs.

2018 American Gas Association Study on the Implications of Policy-Driven Residential Electrification. July 2018. For AGA, Mr. Sloan led a study to determine the cost implications of AGA residential electrification scenarios.

2015 Ontario Natural Gas Market Review: Assessing Ontario Natural Gas Market Requirements. January 2016. Mr. Sloan completed a detailed assessment of Ontario natural gas market requirements for Union Gas Limited, and presented the conclusions of the assessment to the Ontario Energy Board ("OEB") during the OEB 2016 Natural Gas Market Review.

Analysis of the Value of Nexus Pipeline Capacity to DTE Gas Customers. December 2015. Mr. Sloan completed a detailed assessment of the value of holding Nexus pipeline capacity on DTE Gas customers for DTE Gas. The assessment concluded that holding Nexus Pipeline capacity would provide long term benefits to DTE Gas customers.

Analysis of the Value of Nexus Pipeline Capacity on Michigan Energy Markets. November 2015. Mr. Sloan completed a detailed assessment of the value of holding Nexus pipeline capacity on Michigan Energy Markets for DTE Electric. The assessment concluded that holding Nexus Pipeline capacity would provide long term benefits to DTE Electric customers.

Analysis of Union Gas Avoided Costs 2016, 2018. For Union Gas, Mr. Sloan prepared an assessment of the Union Gas estimates of avoided costs used to evaluate DSM programs. The assessment included recommendations for revisions to the avoided cost estimation methodology.

Analysis of Impact of Changing North American Supply and Demand on Union Gas Pipeline Facilities. September 2014. For Union Gas, Mr. Sloan prepared an assessment of the impact of natural gas market changes on planned Union gas facilities. The assessment concluded that new Union Gas facilities would continue to be used and useful for the foreseeable future.

Analysis of the Impact of Changing Natural Gas Market Conditions on ATCO Pipelines Market Risk. January 2014. On behalf of ATCO Pipelines, Mr. Michael D. Sloan completed an assessment of the impact of recent natural gas market changes on ATCO Pipeline market risk. The assessment reviewed the changes in natural gas supply and transportation on market risks for shippers and customers in Alberta.

Analysis of Natural Gas Market Outlook and Options for Gaz Metro, Quebec, Canada, 2013. Mr. Sloan completed an assessment of natural gas market conditions including expected pipeline flows and constraints impacting the Gaz Metro supply planning.

Analysis of Value of Proposed Natural Gas Storage Facilities 2013: Mr. Sloan used his storage valuation model to evaluate the potential value of contracting for capacity on a proposed storage facility for Heritage Gas, Nova Scotia Canada.

Analysis of Natural Gas Supply Options, Centra Manitoba Gas Company – a Division of Manitoba Hydro, 2006-2007 and 2010 -2012: Mr. Sloan prepared a detailed assessment of natural gas supply options for Centra Manitoba Natural Gas. The review included detailed assessment of customer demand patterns relative to industry standards, availability and likely costs of alternative supply strategies capable of meeting demand. The assessment also included evaluation of the clients' current facility contracts, and recommendations for future natural gas facility development and contracting practices. The review includes an assessment of likely pipeline flows and tariffs on the TransCanada Pipeline system.

Storage Market Concentration, Union Gas Limited, 2005 – 2006: On behalf of Union Gas, Mr. Sloan evaluated natural gas storage market concentration and natural gas storage market power in Ontario and the Great Lakes Basin. His report included an assessment of the workably competitive market region for Union Gas storage based on an analysis of market liquidity, connectivity, and market concentration. Mr. Sloan also testified before the Ontario Energy Board on behalf of Union Gas Limited on these issues. At the conclusion to this proceeding the Ontario Energy Board deregulated more than 50 Bcf of Union Gas Storage.

Analysis of Optimum Storage Utilization, MichCon Gas, 2006, 2008, 2011: Mr. Sloan has prepared a series of analyses of the optimum storage utilization for the MichCon Gas local distribution company business to support MichCon regulatory proceedings related gas supply costs and storage utilization. The analyses evaluated the value of existing MichCon gas storage to LDC customers based on different weather patterns and usage scenarios.

Analysis of Value of Proposed Natural Gas Storage Facilities to Nova Scotia Power and Light (NSPI) – 2008: Mr. Sloan used his storage valuation model to evaluate the potential value of contracting for capacity on a proposed storage facility to NSPI.

Analysis of the Impact of LNG on Natural Gas Markets in Quebec, Rabaska Limited, 2005 – 2006: Mr. Sloan prepared a detailed analysis and forecast of the likely impacts of an LNG import facility located in Quebec on local, regional, and US and Canadian natural gas markets. The analysis concluded that the facility would substantially reduce natural gas prices in the region, and increase supply options and supply reliability. The report was filed with the Canadian Environmental Assessment Agency by Rabaska Limited as part of the facility approval process.

Analysis of Natural Gas Market Liquidity at Points Affecting New York State LDC's, Northeast Gas Association, 2003: Mr. Sloan co-authored a major study of natural gas market liquidity for the Northeast Gas Association to identify liquid markets for natural gas commodity purchases. The study included development of new approaches to evaluating market liquidity in the Northeastern U.S., and identified market centers that could be considered sufficiently liquid to provide a reliable source of natural gas.

Analysis of Natural Gas and Energy Price Volatility, for the American Gas Foundation and the Oak Ridge National Laboratory, 2003: Mr. Sloan managed a major study and co-authored a report on natural gas and energy price volatility for the American Gas Foundation.

Multi-Client Study, American Gas Association and Interstate Natural Gas Association of America: Mr. Sloan conducted the analysis, and co-authored the report "Short-term Natural Gas Markets" which was widely cited in FERC Order 637. The analysis was used by FERC to provide quantitative support for the removal of price caps in the short-term capacity release market

Propane Market Analysis

Annual Retail Propane Sales Report: U.S. Odorized Propane Sales by State and End-Use Sector: 2018 – 2020: Mr. Sloan has managed a major project to collect and analyze annual propane sales data for the Propane Education and Research Council (PERC). This effort represents the only currently available data source on state-by-state retail propane sales and includes the collection and processing of survey responses from more than 2000 propane marketers.

Propane Market Forecast Model Development: Mr. Sloan managed the development and implementation of two major propane demand forecasting models for the PERC. The models provide the only publicly available forecasting capability at the State and County levels. The Propane Database and Forecasting Model (PDFM) provides State by State assessments of the total odorized propane market by end-use, including residential, commercial, on-road vehicle, industrial, and portable cylinder markets. The County Residential Propane Model (CRPM) provided propane markets with a customizable forecasting tool capable of evaluating residential demand on a county-by-county basis.

Regulatory and Market Support, National Propane Gas Association, 2008 – 2019. Mr. Sloan provides market and regulatory analysis of issues influencing the propane industry for the National Propane Gas Association.

Assessment of the EIA Regional Residential Propane Model and Regional Residential Distillate Model, U.S. Energy Information Administration, 2006/2007. Mr. Sloan was asked by the EIA to peer review the EIA

Residential Short Term Energy Model residential propane and distillate modules. The review included an in-depth review of the two modules, and recommendations to the EIA for model improvements.

EXPERT TESTIMONY

1. Written evidence of Dr. Michael O Lerner and Michael D. Sloan, *Long term natural gas transmission expansion economics,* 1995. Mr. Sloan submitted written evidence and testified on behalf of Union Gas Limited before the Ontario Energy Board in EBRO 486. Mr. Sloan's evidence concerned the long-term economics of pipeline expansion on the Union Gas system.
2. Written evidence of Dr. Michael O Lerner and Michael D. Sloan, *Long term natural gas transmission expansion economics,* 1996. Mr. Sloan submitted written evidence and testified on behalf of Union Gas Limited before the Ontario Energy Board in EBLO 251. Mr. Sloan's evidence concerned the long-term economics of pipeline expansion on the Union Gas system.
3. "Written Evidence of Bruce B. Henning and Michael D. Sloan", TransCanada PipeLines Limited, Hearing Order RH-1-2002 (dated May 2002). Mr. Sloan submitted written evidence before the National Energy Board on behalf of Enbridge Gas Distribution Inc., Societe En Commandite Gaz Metro, and Union Gas Limited. Mr. Sloan's written evidence concerned the proposed establishment of the Southwest Zone and its impact on market liquidity.
4. "Analysis of FERC Staff Report Investigating California Natural Gas and Electricity Prices", San Diego Gas & Electric Co., Docket Nos. EL00-95-045 and EL00-98-42, prepared by Bruce B. Henning and Michael Sloan, (dated October 15, 2002) and submitted on behalf of Energy and Environmental Analysis, Inc. ("EEA") before the Federal Energy Regulatory Commission ("FERC"). Mr. Sloan's report concerned issues related to FERC's investigation of natural gas and electricity prices.
5. "Written Evidence of Bruce B. Henning and Michael D. Sloan on Behalf of Union Gas Limited", Hearing Order RP-2000-0005 (dated October 29, 2003). Mr. Sloan submitted written evidence on behalf of Union Gas Limited before the Ontario Energy Board. Mr. Sloan's written evidence addressed issues related to the compensation of landowners for the use of natural gas storage pools located on their property.
6. "Written Evidence of Bruce B. Henning and Michael D. Sloan", TransCanada PipeLines Limited, Hearing Order RH-3-2004 (dated June 21, 2004). Mr. Sloan submitted written evidence and testified before the National Energy Board on behalf of Enbridge Gas Distribution Inc., Societe En Commandite Gaz Metro, and Union Gas Limited.
7. Report "The Impact of Rabaska LNG Imports on Quebec and Ontario Natural Gas Markets", authored by Bruce B. Henning and Michael Sloan (dated November 2005) and submitted on behalf of Rabaska Limited Partnership before the Canadian Environmental Assessment Agency.
8. Report "Analysis of Competition in Natural Gas Storage Markets For Union Gas Limited." 2006. Authored by Bruce B. Henning, Michael D. Sloan, and Richard Schwindt and submitted before the Ontario Energy Board Natural Gas Electricity Interface Review EB-2005-0551. 2006. Mr. Sloan testified on behalf of Union Gas Limited before the Ontario Energy Board of Canada.
9. Report "Storage Planning and Optimization for MichCon GCR Customers", December 2007. Authored by Bruce B. Henning and Michael D. Sloan and submitted on behalf of MichCon before the Michigan Public Service Commission U-15451.
10. Report "Assessment of Natural Gas Commodity Options for Centra Gas Manitoba". February 2009. Authored by Bruce B. Henning and Michael D. Sloan and submitted on behalf of Centra Gas Manitoba before the Manitoba Public Utilities Board.
11. Report "Dawn Gateway Pipeline Expansion Project: Market Fundamentals and Market Impact of Project Construction". Authored by Bruce B. Henning and Michael D. Sloan and submitted on behalf of Union Gas before the Canada National Energy Board.

12. Expert witness report “Opinions and Report on Propane Markets and Prices in Minnesota Related to Minnesota Attorney General Counterclaim and Answer”. February 2011. Authored by Mr. Michael D. Sloan and submitted on behalf of Ferrellgas, L.P. before the State of Minnesota District Court, Second Judicial District.
13. Report “ICF 2011 Addendum to the 2007 ICF Report: Storage Planning and Optimization for MichCon GCR Customers”, December 2011. Authored by Bruce B. Henning and Michael D. Sloan and submitted on behalf of MichCon before the Michigan Public Service Commission U-16921.
14. Report “Impact of Changing Supply Dynamics on the Ontario Natural Gas Market”, January 30, 2013. Authored by Mr. Bruce B. Henning, Mr. Michael D. Sloan, and Ms. Briana Adams, and submitted on behalf of Union Gas Limited before the Ontario Energy Board in EB-2013-0074.
15. Report “Review of Natural Gas Pipeline Market Activity around the Dawn Hub”. May 2013. Authored by Mr. Bruce B. Henning and Mr. Michael D. Sloan and submitted on behalf of Gaz Métro before the Quebec Public Utilities Board.
16. Expert Witness Report and Testimony “Impact of Changing Natural Gas Market Conditions on ATCO Pipelines Market Risk”. January 2014. Authored by Mr. Michael D. Sloan and submitted on behalf of ATCO Pipeline before the Alberta Utilities Board. Mr. Sloan testified on behalf of ATCO Pipelines before the Alberta Utilities Board.
17. Expert Witness Report and Testimony “Updated Assessment of Alton Natural Gas Storage”, July 2014, Authored by Mr. Leonard Crook and Mr. Michael Sloan and submitted on behalf of Heritage Gas Limited before the Nova Scotia Utility and Review Board. Mr. Sloan testified on behalf of Heritage Gas before the Nova Scotia Utility and Review Board.
18. Expert Witness Report and Testimony “Impact of Changing North American Supply and Demand on Union Gas Pipeline Facilities”, September 2014. Authored by Mr. Michael D. Sloan and submitted on behalf of Union Gas Limited before the Ontario Energy Board.
19. Expert Witness Report “Evaluation of Union Gas Avoided Costs”, December 2014, Authored by Michael D. Sloan and submitted on behalf of Union Gas Limited before the Ontario Energy Board in Case No. EB-2015-0029. Mr. Sloan testified on behalf of Union Gas Limited before the Ontario Energy Board.
20. Expert Witness Report and Testimony “The Value of Nexus Pipeline Capacity to DTE Gas Customers”, December 2014, Authored by Michael D. Sloan and submitted on behalf of DTE Gas before the Michigan Public Service Commission in Case No. U-17691. Mr. Sloan testified on behalf of DTE Gas before the Michigan Public Service Commission.
21. Expert Witness Report “Impact of Natural Gas Market Trends on Utilization of the Union Gas Dawn Parkway System”, June 30, 2015. Authored by Mr. Michael D. Sloan and submitted on behalf of Union Gas Limited before the Ontario Energy Board.
22. Expert Witness Report and Testimony “Impact of the Nexus Pipeline on Michigan Energy Markets”, November 2015, Authored by Michael D. Sloan and Maria Scheller and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-17920. Mr. Sloan testified on behalf of DTE Gas before the Michigan Public Service Commission.
23. Expert Witness Report and Testimony “The Value of Nexus Pipeline Capacity to DTE Gas Customers”, December 2015, Authored by Michael D. Sloan and submitted on behalf of DTE Gas before the Michigan Public Service Commission in Case No. U-17941. Mr. Sloan testified on behalf of DTE Gas before the Michigan Public Service Commission.
24. Expert Witness Report “2015 Ontario Natural Gas Market Review: Assessing Ontario Natural Gas Market Requirements”, January 2016. Authored by Mr. Michael D. Sloan and submitted on behalf of Union Gas Limited before the Ontario Energy Board. Mr. Sloan presented the results of the analysis to the Ontario Energy Board on behalf of Union Gas Limited.

25. Expert Witness Report and Testimony "Propane Market Trends in the Northeastern U.S. and Atlantic Canada", January 2016, Authored by Michael D. Sloan and submitted on behalf of Heritage Gas before the Nova Scotia Utility and Review Board. Mr. Sloan testified on behalf of Heritage Gas before the Nova Scotia Utility and Review Board.
26. Expert Witness Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", October 2016, Authored by Michael D. Sloan and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-18143.
27. Expert Witness Testimony "The Value of Nexus Pipeline Capacity to DTE Gas Customers", December 2016. Authored by Michael D. Sloan and submitted on behalf of DTE Gas before the Michigan Public Service Commission in Case No. U-18243.
28. Expert Report "ICF Review of MNP Proposal for Irving Oil Load Retention Service". Authored by Michael D. Sloan and submitted on behalf of Nova Scotia Power before the Canada National Energy Board in Case RHW-001-2017.
29. Expert Report "Assessment of the Impact of the TransCanada Dawn LTFP Service Proposal on Natural Gas Markets", Authored by Michael D. Sloan and submitted on behalf of Union Gas Limited before the Canada National Energy Board in Case RH-003-2017.
30. Confidential Expert Report "Analysis of Merchant Natural Gas Storage Competition in Ontario", January 2017. Authored by Michael D. Sloan and submitted on behalf of Enbridge, Inc. and Spectra Energy Corporation to the Competition Bureau Canada.
31. Expert Witness Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", October 2017, Authored by Michael D. Sloan and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-18403.
32. Expert Report "Rebuttal to Evidence of James Grevatt on 2017 FortisBC LTGRP Testimony" addressing non-pipeline solutions. Authored by Michael Sloan and John Dikeos and submitted on behalf of FortisBC to the British Columbia Utilities Commission in Project No. 1598946.
33. Expert Report "Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment", January 2018. Authored by Michael D. Sloan and John Dikeos and submitted on behalf of Union Gas Limited and Enbridge Gas Limited, before the Ontario Energy Board in Case EB-2017-0128.
34. Expert Witness Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", September 2018, Authored by Michael D. Sloan and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-18412.
35. Expert Witness Testimony "The Value of Nexus Pipeline Capacity to DTE Gas Customers", April 2018. Authored by Michael D. Sloan and submitted on behalf of DTE Gas before the Michigan Public Service Commission in Case No. U-18412.
36. Expert Witness Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", September 2018, Authored by Michael D. Sloan and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-20221.
37. Expert Report "Impact of Changing Supply Dynamics on the Ontario Natural Gas Market", July 2019. Authored by Michael Sloan and Srirama Palagummi and submitted on behalf of Enbridge Gas Limited, before the Ontario Energy Board in Case EB-2019-0159.
38. Expert Report "Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals", March 2020. Authored by Michael Sloan and Peter Narbaitz and submitted on behalf of AltaGas to the Public Service Commission of the District of Columbia, Formal Case No. 1142.

39. Expert Witness Testimony on behalf of Summit Utilities before the Maine Public Utilities Commission regarding the value of contracted pipeline capacity on the Atlantic Bridge Pipeline to natural gas consumers in the Summit Utilities Maine service territory. June 2020. MPUC Docket No. 2019-00185.
40. Expert Witness Testimony report and deposition, "Opinions and Report on Propane Markets and Prices in Michigan Related to Michigan Attorney General Complaint June 27, 2018". Authored by Mr. Michael D. Sloan and submitted on behalf of AmeriGas before the State of Michigan Circuit Court for the 38th Judicial Circuit, Monroe County. June 2020.
41. Expert Report, "IRP Jurisdictional Review", September 2020. Submitted on behalf of Enbridge Gas Limited before the Ontario Energy Board in Case EB-2020-0091.
42. Expert Witness Rebuttal Testimony on behalf of Summit Utilities before the Maine Public Utilities Commission regarding the value of contracted pipeline capacity on the Atlantic Bridge Pipeline to natural gas consumers in the Summit Utilities Maine service territory. July 2021. MPUC Docket No. 2019-00185.
43. Expert Report "Assessment of the Value of the Enbridge Gas Dawn to Corunna Storage Project: Potential Value of Incremental Storage Capacity and Market-Based Alternatives to Enbridge Gas", February 2022. Authored by Michael Sloan and Andrew Griffith and submitted on behalf of Enbridge Gas Limited, before the Ontario Energy Board in Case EB-2022-0086.

SELECTED PUBLICATIONS AND PRESENTATIONS

Harry Vidas, Michael Sloan. "Pipeline Markets in Transition: Cost Impacts of FERC Order 636." *Gas Research Institute*, March 1998.

Michael Sloan, Paul Friley. "Natural Gas Storage Overview in a Changing Market Environment." *Gas Research Institute,* GRI-99/0200, February 2000.

Michael Sloan, Paul Friley, Bruce Henning. "Restructuring Activity of Natural Gas Local Distribution Companies." *Gas Research Institute,* GR00/0018, June 2000.

Bruce Henning, Michael Sloan, Maria deLeon. "Natural Gas and Energy Price Volatility." *Prepared for the Oak Ridge National Laboratory by the American Gas Foundation*, October 2003.

Michael Sloan, Bruce Henning, Sol deLeon, David Clayton. "Propane Industry Issues and Trends." *Propane Education and Research Council*, June 2004.

Michael Sloan, Bruce Henning, Sol deLeon, David Clayton. "Propane Industry Issues and Trends II." *Propane Education and Research Council*, January 2005

Michael Sloan, Bruce Henning. "Propane Industry Issues and Trends III." *Propane Education and Research Council*, August 2005.

Michael Sloan. "Propane Market Growth: A Review of Propane Market Trends and the Role of the PERC Market Metrics Initiative", Prepared for the National Propane Gas Association, January 30, 2006.

Michael Sloan, Bruce Henning. "Propane Industry Issues and Trends IV", *Propane Education and Research Council*, August 2006.

Michael Sloan. "Natural Gas Supply and Demand in an Uncertain Environment". Canadian Institute Conference on Natural Gas Storage, September 2008.

Michael Sloan, Richard Meyer. "2009 Propane Market Outlook – Assessment of Key Market Trends, Threats, and Opportunities Facing the Propane Industry Through 2020." *Propane Education and Research Council*, September 2009.

Michael Sloan. “What Keeps You Up at Night? Natural Gas Market Planning in an Uncertain Environment”. Canadian Institute Conference on Natural gas Storage, February 2009.

Michael Sloan. “Back to the Future? Impact of Market Volatility and Uncertainty on Natural Gas Supply and Infrastructure”. Canadian Institute Conference on Natural Gas Infrastructure and Supply, November 2009.

Michael Sloan, Richard Meyer. “2010 Propane Market Outlook – Assessment of Key Market Trends, Threats, and Opportunities Facing the Propane Industry Through 2020. ” *Propane Education and Research Council*, June 2010.

Michael Sloan, Bruce Hedman, et al., “Strategic Market Assessment for Commercial Sector Propane Sales” *Propane Education and Research Council*, February 2011.

Michael Sloan, K.G. Duleep, et al. “Economic Impact of the Propane Green Autogas Solutions Act of 2011 (H.R. 2014)”, *National Propane Gas Association*, October 2011.

Michael Sloan. “Industry at a Crossroads”, *Propane Education and Research Council*, May 2012.

Michael Sloan, Warren Wilczewski. “2013 Propane Market Outlook – Assessment of Key Market Trends, Threats, and Opportunities Facing the Propane Industry Through 2020. ” *Propane Education and Research Council*, April 2013.

Michael Sloan. “Implications of U.S. natural gas liquids (NGL) market developments on European petrochemical and NGL markets”, Platt’s European Petrochemicals Conference, Düsseldorf, Germany. March 2014.

Michael Sloan. “A Detailed Look at the Impact of Cochin Pipeline Reversal on Propane Markets in the Midwest”, presented to the Midwest Governors Association Propane Supply Chain Working Group Meeting June 4, 2014, Madison Wisconsin.

Michael Sloan, Warren Wilczewski. “Impact of the Cochin Pipeline Reversal on Consumer Propane Markets in the Midwest”, *Propane Education and Research Council*, August 2014.

Michael Sloan, “NGL Production Outlook in the Utica and Marcellus”, NGL Gold Rush Executive Briefing, Cleveland, Ohio. September 2014.

Michael Sloan, “NGL Production, Economics, and Pricing in the Utica and Marcellus”, NGL Gold Rush Summit, Cleveland, Ohio. September 2014.

Michael Sloan. “North American Propane and Butane Demand, Markets and Pricing”, Platt’s 4th Annual NGL’s Conference, Houston, Texas, September 2014.

Michael Sloan, Warren Wilczewski. “Impact of the U.S. Consumer Propane Industry on U.S. and State Economies in 2012”, *Propane Education and Research Council*, November 2014.

Michael Sloan. “Future Trends: Assessing Ontario Natural Gas Market Requirements Through 2020”, December 2014. Submitted on behalf of Union Gas Limited before the Ontario Energy Board, and presented to the Ontario Energy Board Stakeholder Conference, December 2014.

Michael Sloan. “NGL Market Outlook in a Dynamic Oil Price Environment”, *2014 NGL Forum*, San Antonio, Texas, December 2014.

Michael Sloan. “Consumer Propane Markets in a Changing Oil Price Environment”, 2015 NPGA Southeaster Convention, Atlanta, Georgia, April 2015.

ICF Consulting Canada, *“Impact of Energy East on Ontario Natural Gas Prices”,* April 8, 2015, Prepared for the Ontario Energy Board by Michael Sloan, with Kevin Petak, Hua Fang, Leonard Crook.

Michael Sloan. “Outlook for Natural Gas Demand Growth in the Industrial Sector”, 2015 ARGUS Natural Gas Markets Conference, Houston, Texas, May 2015.

Michael Sloan. "The Market for Global Petrochemical Feedstocks in a Changing Oil Price Environment – Current and Future Trends", 2015 Platt's Asian Petrochemical Markets Conference, Shanghai, China, August 2015.

Michael Sloan. "Global LPG Markets: The Outlook for Propane and Butane", Platt's 5th Annual NGL's Conference, Houston, Texas, September 2015.

Michael Sloan. "2016 Propane Market Outlook – Key Market Trends, Opportunities and Threats Facing the Propane Industry Through 2025. " *Propane Education and Research Council*, November 2015.

Michael Sloan. "Evaluating the End Game: The Outlook for the NGL Industry in a Low Oil Price Environment", *2015 NGL Forum*, San Antonio, Texas, December 2015.

Michael Sloan. "2015 Ontario Natural Gas Market Review: Assessing Ontario Natural Gas Market Requirements", January 2016. Submitted on behalf of Union Gas Limited before the Ontario Energy Board, and presented to the Ontario Energy Board Stakeholder Conference, January 2016.

Michael Sloan. "Is Demand Back?? Keeping up with Supply?? Things are not always as they seem – The Big Picture", 2017 NGL Forum, Atlanta, April 2017.

Michael Sloan. "2017 Propane Market Outlook: Current Market Conditions and the Outlook Through 2025", NPGA Southeast Convention, Nashville, April 2017.

Michael Sloan. "Business Risk: Implications of a Low Carbon World for Natural Gas LDC's", 2017 NGL Forum, Boston, June 2017.

Michael Sloan. "The Impact of Infrastructure Development Trends on Midwest Natural Gas Markets", 2017 NGL Forum, September 2017.

Michael Sloan and John Dikeos. "Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment for Ontario", Prepared for Union Gas and Enbridge Gas, March 2018.

Michael Sloan. "2018 Propane Market Outlook: Coping with Changing Markets", NPGA Southeast Convention, Atlanta, April 2018.

Michael Sloan, Joel Bluestein, Eric Kuhle. "Implications of Policy-Driven Residential Electrification – An American Gas Association Study prepared by ICF", July 2018.

Michael Sloan. "2019 Propane Market Outlook: Warning Signs in a Changing Market 2025", NPGA Southeast Convention, Atlanta, April 2019.

Eric Kuhle and Michael Sloan, "2018 Propane Industry's Economic Impact Report; Impact of the U.S. Consumer Propane Industry on U.S. and State Economies in 2018", Propane Education and Research Council, April 2020.

Statement to the Michigan State Senate and House Committees on the impact of a potential shutdown of Enbridge Line 5 on behalf of the Michigan Propane Gas Association. March 2021.

Michael Sloan. "2021 Propane Market Outlook: Adapting to Change – Electrification and Decarbonization", NPGA Southeast Convention, Atlanta, October 2021.

EMPLOYMENT HISTORY

ICF	Managing Director	2016 - Present
ICF International	Project Manager to Principal	2007 – 2016
Energy and Environmental Analysis, an ICF International Company	RA to Project Manager	1981-2006

FORM A

Proceeding:……EB-2022-0200………

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ....Abbas Lakha....(*name)*. I live at ....Richmond Hill.... (*city)*, in the ....Province.... (*province/state*) of ....Ontario.... .

2. I have been engaged by or on behalf of ....Enbridge Gas, as an employee of EY.... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ....September 27, 2022....

ALakha

Signature

FORM A

Proceeding:……EB-2022-0200………

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ....Andy Grainger............(*name)*. I live at ...Komoka................... (*city)*, in the ..Province........... (*province/state*) of ..Ontario................... .

2. I have been engaged by or on behalf of Enbridge Gas, as an employee of EY (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date .September 28, 2022.......

Andy Grainger

Signature

FORM A

Proceeding: 2024 Rebasing

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Andrew Griffith. I live in Denver in the state of Colorado.

2. I have been engaged by or on behalf of Enbridge Gas Inc. to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date September 29, 2022

Andrew Griffith
Signature

FORM A

Proceeding: EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Michael Sloan ....(*name*). I live at Great Falls .... (*city*), in the State .... (*province/state*) of Virginia ....

2. I have been engaged by or on behalf of Enbridge .... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ....September 29, 2022..........

Signature

FORM A

Proceeding: # EB-2022-0200, EGI 2024 Rebasing

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Larry Kaufmann (*name*). I live at Austin (*city*), in the State (*province/state*) of Texas :

2. I have been engaged by or on behalf of EGI (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date August 9, 2022

Larry Kaufmann

Signature

ADMINISTRATION

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Enbridge Gas 2024 Rebasing Application Background

On October 31, 2022, Enbridge Gas filed a cost of service and rebasing application for 2024 rates and for approval of an incentive rate-setting mechanism (IRM) for the following four years. The Application was filed in two parts. The majority of the evidence, which captured the revenue requirement and the IRM for 2025 to 2028, was filed on October 31, 2022. The balance of the evidence, which contained cost allocation and rate design, was filed on November 30, 2022.

Following an Issues Conference, on January 27, 2023, the OEB issued Procedural Order No. 2 which set out the Issues List for this proceeding, divided into Phase 1 and Phase 2. In general, the Phase 1 issues (Issues 1 to 41) were directed at setting interim rates to be effective January 1, 2024, whereas the Phase 2 issues (Issues 42-58) were directed at issues that were either not necessary to set rates for January 1, 2024, or issues where the outcomes could be reflected in adjustments to the interim rates approved in Phase 1.

Through 2023, the OEB conducted Phase 1 of the proceeding, starting with a discovery process and a Settlement Conference.

Through the Phase 1 Settlement Agreement, the parties agreed to a resolution of some Phase 1 issues, and also agreed that some Phase 1 issues should be deferred to Phase 2. Specifically, within the OEB-approved Phase 1 Settlement Agreement[1], parties agreed to defer the following issues to Phase 2: load balancing costs (Issue 18a), storage space and deliverability (Issue 39), operational contingency space (Issue 18c) and inclusion of the Dawn to Corunna Replacement Project in rate base (Issue 6).

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[1]EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023.

Additionally, within the OEB-approved Phase 1 Settlement Agreement, the parties agreed to address cost allocation and rate harmonization options in a new Phase 3 of the proceeding. Phase 3 would address several issues from Phase 1 that are being deferred (parts of Issues 24 to 28) as well as Issues 54 to 57 (Harmonized Rate Classes) that were included as part of the Phase 2 Issues List.

Following the Settlement Conference, the OEB conducted an Oral Hearing to address the unsettled Phase 1 issues. The OEB rendered its Phase 1 Decision and Order on December 21, 2023. Among other things, the Phase 1 Decision and Order includes several directions for items that Enbridge Gas is expected to address and/or report on in Phase 2 of the Rebasing proceeding.

After a draft rate order process, the OEB approved Enbridge Gas's interim 2024 rates on April 11, 2024, with implementation starting May 1, 2024.

Phase 2 Evidence

Phase 2 of this 2024 Rebasing Application is being filed under a new docket number, EB-2024-0111. Throughout this submission, any reference to Phase 1 is referring to the EB-2022-0200 record.

This filing includes all the evidence required to address the issues that are included in Phase 2. Those issues include: (i) the Phase 1 issues that were deferred to Phase 2 as a result of the Settlement Agreement; (ii) the Phase 2 issues identified in Procedural Order No. 2 (other than Issues 54 to 57, which are for Phase 3); and (iii) the items from the Phase 1 Decision that Enbridge Gas is expected to address and/or report on in Phase 2 of the Rebasing proceeding.

This filing includes updated versions of evidence previously filed for Phase 1 where that evidence is relevant to Phase 2. Enbridge Gas has not refiled evidence unless it is directly related to the Phase 2 issues.

This filing also includes new evidence related to directives in the Phase 1 Decision for information to be provided in Phase 2 of this Application. The OEB's directives in relation to the customer revenue horizon have not been addressed, because that part of the Phase 1 Decision has been stayed until April 30, 2024, which is expected to be extended or made permanent in the event that Bill 165 (*Keeping Energy Costs Down Act, 2024*) is passed.

The complete list of evidence filed in this submission is provided at Exhibit 1, Tab 1, Schedule 1. New evidence, not previously filed in Phase 1, is noted. For ease of reference, Enbridge Gas has maintained the same numbering as Phase 1 for the previously filed evidence and inserted the new evidence in sequence. The Phase 2 evidence, as it is being filed as a stand-alone submission, does not indicate where an update has been made within evidence. Instead, Enbridge Gas has added "Phase 2" to the headers to differentiate between the updated evidence filed and the original evidence filed in October/November 2022.

In the attachments to this evidence, Enbridge Gas sets out the approvals requested as well as a mapping of the Phase 2 issues to evidence.

<u>Overview of Phase 2</u>

In Phase 2 of the 2024 Rebasing Proceeding, Enbridge Gas is requesting approvals for a number of items, related primarily to six areas: (i) IRM for 2025 to 2028; (ii) Dawn to Corunna Project; (iii) gas and gas storage costs; (iv) energy transition specific proposals (low-carbon energy and Energy Transition Technology Fund (ETTF)); (v) deferral and variance accounts; and (vi) scorecard metrics.

The full list of approvals requested in Phase 2 is set out in Attachment 1. Most of these requested approvals are the same as were included in the Phase 1 filing. The new requested approvals (as compared to what was previously requested and reflected in the Issues List) are the following: (i) inclusion of Dawn to Corunna project costs in rate base; (ii) approval of two new deferral and variance accounts – an OEB Cost Assessment Variance Account and an OEB Directive Deferral Account; and (iii) a change to the calculation of the Meter Reading Performance Metric. Enbridge Gas's evidence also includes some updates to its proposals for the IRM, including in relation to the incremental capital module (ICM) and the off-ramp.

Enbridge Gas is filing evidence to respond to the OEB's directives from the Phase 1 Decision. No discrete approvals are sought in relation to those items, though the Company's proposal for Asset Life Extension includes a proposal to change ICM parameters. Attachment 2 sets out the directives that Enbridge Gas is addressing in its evidence. These include directives from previous proceedings (other than Phase 1) which are relevant to the issues in Phase 2.

The OEB has approved interim 2024 rates that reflect the impacts of all determinations in Phase 1. The impact of the approvals requested in Phase 2 is that the revenue requirement and revenue deficiency would increase by $17.8 million. As shown in Table 1, this is primarily driven by the inclusion of the Dawn to Corunna Project in rate base, with modest impacts also seen from the implementation of the updated storage cost allocation methodology.

Table 1

Phase 2 2024 Revenue Deficiency

Line No.	Update	Impact ($ millions)
1	Include revenue requirement impacts of Dawn to Corunna	18.1
2	Incorporate impact of updating Unregulated Storage Cost Allocators	(0.2)
3	Incorporate impact to working capital in rate base	(0.1)
4	Phase 2 2024 Revenue Deficiency	17.8

The 2024 bill impacts for individual customers vary by rate zone and rate class. For a typical residential sales service customer, the updated 2024 rates, reflecting the Phase 2 proposals, result in an annual bill increase of:

- $3.14 (or 0.2% of total bill) for a Rate 1 customer in the EGD rate zone;
- $3.73 (or 0.3% of total bill) for a Rate 01 customer in the Union North rate zone; and
- $2.75 (or 0.3% of total bill) for a Rate M1 customer in the Union South rate zone.

Issues List

In Procedural Order No. 2 in Phase 1, the OEB established an Issues List for both Phase 1 and Phase 2. As described above, through the Phase 1 Settlement Agreement, certain issues from Phase 1 were moved to Phase 2, and certain issues from Phase 2 were moved to Phase 3.

Enbridge Gas expects that the existing issues can accommodate all or most of the items to be determined in Phase 2. In Attachment 3, Enbridge Gas sets out a draft issues list which re-orders the relevant items from the initial Issues List. For convenience, Attachment 3 also identifies the Phase 2 evidence that is responsive to each issue.

Rate Implementation and Requested Effective Date

Enbridge Gas is requesting approval of updated 2024 rates effective January 1, 2024, as part of Phase 2. As previously noted, the OEB approved interim 2024 rates in the Phase 1 Rate Order on April 11, 2024. Enbridge Gas is proposing to update the interim 2024 rates to reflect the OEB's findings in the Phase 2 Decision as part of the Phase 2 draft rate order process. The 2024 rates would remain interim pending the outcome of Enbridge Gas's motion for review and variance of the Phase 2 Decision (EB-2024-0078).

Any rate variance between the effective date approved by the OEB as part of Phase 2 and the implementation date will be included in a rate adjustment rider (Rider E), consistent with the rate adjustment rider approved in the Phase 1 rate order.

2025 Rates

Given the timing of Phase 2 of this proceeding and given that approvals from this Phase 2 (especially in relation to the IRM) are needed to set rates for 2025, Enbridge Gas believes that it is appropriate to consider now how best to have timely implementation of 2025 rates.

As explained in Enbridge Gas's April 4, 2024, letter to the OEB, the Company's original plan had been to file Phase 2 evidence on October 26, 2023. The OEB's direction in response was to wait for the Phase 1 Decision before filing the evidence, to minimize the need for future evidence updates. Enbridge Gas has filed this updated Phase 2 evidence as soon as possible following the Phase 1 Decision, taking into account the timing of Bill 165 which had direct impacts on the scope of Phase 2.

Enbridge Gas will be requesting that the OEB approve and implement 2025 rates as soon as possible after the Phase 2 Decision on the IRM is complete. Enbridge Gas will be requesting, if necessary, that 2025 rates be set on an interim basis of January 1, 2025, until the updated rates can be reviewed and approved. Enbridge Gas expects that it will propose that the OEB approve final 2025 rates as part of the Phase 2 draft rate order process. Enbridge Gas would file the required information and evidence relevant to the IRM rate adjustment for 2025 in the rate order process. The approved 2025 rates would then include the outcomes of the Phase 2 Decision, including the changes to 2024 rates effective January 1, 2024, as well as the IRM adjustment to set 2025 rates effective January 1, 2025.

Requested Approvals

Set out below are the approvals requested by Enbridge Gas in Phase 2. The items that are new, as compared to what was noted in the Phase 1 filing, are noted in bold.

Exhibit 1 – Administration Documents

Approval of Enbridge Gas's proposals in the Administration binder for Phase 2 including approvals of:

- Scorecard metrics
    - **to exclude inaccessible meters from the calculation of MRPM starting in January 2024**[1]
- Energy Transition Technology Fund (ETTF)
- Harmonized unregulated storage allocation methodology
- **Dawn to Corunna Project inclusion in Rate Base**[2]

Exhibit 4 – Operating Expenses

Approval of Enbridge Gas's 2024 Test Year Operating Expenses being considered in Phase 2, including approvals of:

- 2024 Test Year load balancing gas cost forecast
- Procurement of additional 10 PJ of market-based storage not included in 2024 Test Year gas cost forecast
- Operational contingency space
- Low-Carbon Energy

[1] New Approval Request
[2] New Approval Request

- Implementation of a proposed new Low-Carbon Voluntary Program in 2025, at which time the existing pilot VRNG program would be discontinued
- Procuring low-carbon energy as part of Enbridge Gas's gas supply commodity portfolio and recovering the associated incremental costs through the proposed cost recovery mechanism

Exhibit 8 – Rate Design

Approval of Enbridge Gas's 2024 rate design proposals being considered in Phase 2, including approvals of:

- Rider N – ETTF
- Rider L – Low-Carbon Voluntary Program Charge

Exhibit 9 – Deferral and Variance Accounts

Approval of Enbridge Gas's establishment of new deferral and variance accounts being proposed in Phase 2 including approvals of the following deferral and variance accounts:

- Energy Transition Technology Fund Variance Account
- **OEB Cost Assessment Variance Account** [3]
- **OEB Directive Deferral Account**[4]

Exhibit 10 – Incentive Rate-Setting Proposal

Approval of Enbridge Gas's Incentive Rate-setting Mechanism including approvals of:

- A multi-year price cap incentive rate-setting mechanism

[3] New Approval Request
[4] New Approval Request

Directive Response Summary

OEB File No.	Utility	Directive/Commitment	Response
MAADs and Rate Setting Mechanism Proceeding EB-2017-0306/EB-2017-0307	EGI	File a proposal with respect to the use of excess utility storage from the Union rate zones.	Phase 2 Exhibit 4, Tab 2, Schedule 1
Voluntary RNG Program EB-2020-0066	EGI	Voluntary RNG Program Cost Proposal: Present a proposal for the funding of the costs to operate Enbridge Gas's Voluntary RNG Program (i.e., funded in rates or funded by participants)	Phase 2 Exhibit 4, Tab 2, Schedule 7
Voluntary RNG Program EB-2020-0066	EGI	Reporting on the RNG Program: Enbridge Gas will provide "reporting on Program results (participation, costs, RNG volumes etc.), RNG procurement approaches and experience, observations on the competitive market, discussion of the impact of the CFS, and details relating to go-forward proposals for the future of the Program" as part of Enbridge Gas's rate rebasing application or a future stand-alone application for the program.	Phase 2 Exhibit 4, Tab 2, Schedule 7
EB-2021-0149	EGI	Enbridge Gas has agreed to file evidence in its rate rebasing application (for rates as of January 1, 2024, which will include requests for approvals for the pass-through of gas supply costs) demonstrating that it has fully considered the opportunity to reduce storage costs through inclusion, as part of its load balancing portfolio, of cost-effective market-based alternatives to the purchase of third-party storage. That evidence will include consideration of: (i) the cost of delivered supply (including the commodity cost) in winter in lieu of contracting for additional storage; versus (ii) the cost (savings) of buying gas in summer and the associated additional storage and related costs required to store and redeliver that gas in the winter.	Phase 2 Exhibit 4, Tab 2, Schedule 1 and Phase 2 Exhibit 4, Tab 2, Schedule 1, Attachment 2 and 3

OEB File No.	Utility	Directive/Commitment	Response
2021/22 Storage Enhancement Project EB-2020-0256	EGI	Address the allocation of all costs between Enbridge Gas's rate regulated and unregulated storage business as part of Enbridge Gas's next rate rebasing application.	Phase 2 Exhibit 1, Tab 13, Schedule 2
Dawn to Corunna Replacement Project EB-2022-0086	EGI	Address the extent to which the recovery of the cost of the Project from ratepayers is appropriate	Phase 2 Exhibit 1, Tab 13, Schedule 4
2024 Rebasing Phase 1, EB-2022-0200	EGI	The OEB directs Enbridge Gas to review the energy comparison information currently on its website and printed materials to determine whether it fully discloses what is being compared and on what basis, and what assumptions are being used for the comparison. Enbridge Gas shall either update the information to correct any deficiencies or remove the information. As part of its updated evidence for Phase 2, Enbridge Gas shall provide a report on the review it undertook and the actions it took as a result of the review.	Phase 2 Exhibit 1, Tab 16, Schedule 1
2024 Rebasing Phase 1, EB-2022-0200	EGI	Examine ways in which Enbridge Gas could be provided with an incentive to implement economic alternatives to gas infrastructure replacement projects, including asset life extensions and system pruning, including replacing gas equipment with electric equipment.	Phase 2 Exhibit 1, Tab 17, Schedule 1

OEB File No.	Utility	Directive/Commitment	Response
2024 Rebasing Phase 1, EB-2022-0200	EGI	To address the existing unfunded liability, the OEB directs Enbridge Gas to file evidence in Phase 2 indicating how the annual amounts are calculated and to provide a long-term forecast of the total funds required to pay for site restoration costs. The forecast may be aggregated for the amalgamated utility for 2025, with the expectation that further segmentation may be warranted based on the ten asset accounts to be tracked.	Phase 2 Exhibit 4, Tab 5, Schedule 2
2024 Rebasing Phase 1, EB-2022-0200	EGI	As part of the IRM issue in Phase 2, Enbridge Gas shall file a proposal to reduce the capitalized indirect overheads balance by $50 million in each year of the proposed IRM term and expense it as O&M, consistent with the OEB's findings in this Decision and Order. In that proposal, Enbridge Gas could consider a mechanism similar to the capital pass-through mechanism approved in Union Gas's last IRM framework	Phase 2 Exhibit 10, Tab 1, Schedule 1

Draft Issues List to Evidence Mapping

Issue	Evidence
5) Has Enbridge Gas identified and responded appropriately to all relevant OEB directions and commitments made from previous proceedings?	Phase 2 Exhibit 1, Tab 16, Schedule 1; Phase 2 Exhibit 1, Tab 17, Schedule 1; Phase 2 Exhibit 4, Tab 5, Schedule 2; and Phase 2 Exhibit 10, Tab 1, Schedule 1
A. Incentive Rate-Setting Mechanism (Exhibit 10)	
42) Are the proposed Price Cap Incentive Rate-Setting Mechanism, Annual Rate Adjustment Formula, and term appropriate?	Phase 2 Exhibit 10, Tab 1, Schedule 1
43) Are the proposed elements of Enbridge Gas's Price Cap Incentive Rate-Setting Mechanism appropriate?	Phase 2 Exhibit 10, Tab 1, Schedule 1
44) Is the proposed approach to incremental capital funding appropriate?	Phase 2 Exhibit 10, Tab 1, Schedule 1
45) Is the proposed earnings sharing mechanism appropriate?	Phase 2 Exhibit 10, Tab 1, Schedule 1
46) Is Enbridge Gas's proposal for annual proceedings for clearance of deferral and variance accounts and presentation of utility results (and any ESM amounts) and scorecard results appropriate?	Phase 2 Exhibit 10, Tab 1, Schedule 1
B. Rate Base and Storage	
6) Is the 2024 proposed rate base appropriate?	Phase 2 Exhibit 1, Tab 13, Schedule 4
18) In relation to the 2024 Test Year gas cost forecast, a) Is the 2024 gas supply cost, including the forecast of gas, transportation and storage costs, appropriate?	Phase 2 Exhibit 4, Tab 2, Schedule 1 and Phase 2 Exhibit 4, Tab 2, Schedule 4

Issue	Evidence
c) Is the proposed harmonized approach to determining gas costs (design day, operational contingency space, unaccounted for gas, Parkway Delivery Obligation) appropriate?	
39) Is the proposed harmonized methodology for determining the amount of storage space and deliverability required to serve in franchise customers appropriate, and is the proposed allocation of storage space and deliverability among customers appropriate?	Phase 2 Exhibit 4, Tab 2, Schedule 1 and Phase 2 Exhibit 4, Tab 2, Schedule 5
47) Should the cap on cost-based storage service for in-franchise customers established in the NGEIR decision remain at 199.4 PJ?	Phase 2 Exhibit 4, Tab 2, Schedule 8
48) Is the purchase of storage service at market-based rates by Enbridge Gas from Enbridge Gas for in-franchise customers appropriate?	Phase 2 Exhibit 4, Tab 2, Schedule 9
49) Is the proposal to add 10 PJ of market-based storage at a cost not currently included in the 2024 Test Year gas cost forecast appropriate?	Phase 2 Exhibit 4, Tab 2, Schedule 1
50) Is the allocation of capital assets and costs between utility and non-utility (unregulated) storage operations appropriate?	Phase 2 Exhibit 1, Tab 13, Schedule 4
51) How should the determinations made for the Phase 2 Storage issues be addressed and implemented, including any required changes to 2024 costs and revenues, the Gas Supply Plan and gas supply deferral and variance accounts?	Phase 2 Exhibit 4, Tab 2, Schedule 1

Issue	Evidence
C. Technology Fund & Voluntary RNG Program	
52) Are the specific proposed parameters for an Energy Transition Technology Fund and associated rate rider appropriate?	Phase 2 Exhibit 1, Tab 10, Schedule 7; Phase 2 Exhibit 8, Tab 1, Schedule 2 and Phase 2 Exhibit 9, Tab 1, Schedule 3
53) Are the specific proposals to amend the Voluntary RNG Program and to procure low-carbon energy as part of the gas supply commodity portfolio, appropriate?	Phase 2 Exhibit 4, Tab 2, Schedule 7 and Phase 2 Exhibit 8, Tab 1, Schedule 2
D. Other	
32) Is the proposal to close and continue certain deferral and variance accounts and establish new ones appropriate?	Phase 2 Exhibit 9, Tab 1, Schedule 3
58) Are the proposed scorecard Performance Metrics and Measurement targets for the amalgamated utility appropriate?	Phase 2 Exhibit 1, Tab 7, Schedule 1

PERFORMANCE MEASUREMENT AND SCORECARD

MICHAEL MCGIVERY, DIRECTOR WORK MANAGEMENT SERVICES
LYNN LEE, MANAGER PERFORMANCE REPORTING & ANALYTICS

1. Enbridge Gas has updated this evidence to reflect the following issue that is being addressed in Phase 2 of this Application.

   58) Are the proposed scorecard Performance Metrics and Measurement targets for the amalgamated utility appropriate?

2. The purpose of this evidence is to establish the appropriateness of the current Enbridge Gas performance measures on its OEB Scorecard (scorecard). Enbridge Gas believes that the scorecard metrics are appropriate and believes that the methods for calculating the metrics are appropriate, with the exception of the Meter Reading Performance Measurement (MRPM) target. Enbridge Gas accepts 0.5% for the MRPM target, however, does not believe that inaccessible meters should be included in calculating the target. Enbridge Gas is proposing that inaccessible meters be excluded from the calculation of the MRPM starting in January 2024, as a result of ongoing and persisting meter access issues that are beyond the control of Enbridge Gas to remedy. Enbridge Gas has provided new data to support this proposal starting at section 2, Meter Reading Performance Measurement Proposal, of this evidence.

3. This evidence is organized as follows:
   1. Background
   2. Meter Reading Performance Measurement Proposal
   3. Mitigation Plan

1. Background

1.1 Performance Measurement Scorecard

4. Enbridge Gas's current scorecard was established during the MAADs proceeding[1] and has been reported annually to the OEB as part of the annual Utility Earnings and Disposition of Deferral & Variance Account Balances proceedings. As directed under the OEB's Filing Requirements for Natural Gas Rate Applications, Section 2.1.7, the scorecard includes measures in the following four categories:
    a) Customer Focus - which directs attention to service quality and customer satisfaction with measures to track Enbridge Gas's service appointments, billing accuracy and call centre activities.
    b) Operational Effectiveness - focuses on safety, system reliability, asset management and cost control where metrics are applied to address safety, system reliability, asset management and cost control for the customer.
    c) Public Policy Responsiveness - targets conservation and demand management, and connection of renewable generation which center on natural gas saving metrics.
    d) Financial Performance - looks at financial ratios, and includes interest charges, return on assets and equity.

5. The 20 measures spanning the four categories cover an extensive range of performance indicators, including a combination of Service Quality Requirements (SQRs) and best practice metrics that Enbridge Gas believes ensure the best possible experience for customers.

6. These categories are consistent with performance measures applied to EPCOR Aylmer and Southern Bruce operations along with electric utilities regulated by the

[1] EB-2017-0306/EB-2017-0307.

OEB including but not limited to EPCOR Electricity Distribution Ontario Ltd., London Hydro Inc., Toronto Hydro-Electric System Limited along with many others. However, the required annual metrics as defined by the OEB and set out in the Gas Distribution Access Rule (GDAR) are not consistent with the performance measures applied to the electric utilities, or specifically to the Electricity Distribution System Code (DSC). The DSC does not have a meter reading metric, given the use of automatic meter reading, and Call Answer Services Levels (CASL) are a minimum of 65% compared to GDAR's requirement of 75%.

7. 2023 is the fifth year that Enbridge Gas is presenting the scorecard for the amalgamated utility. Over the next IR term (2025 to 2028), Enbridge Gas will continue to provide the annual scorecard in the Utility Earnings and DispRosition of Deferral & Variance Account Balances proceedings.[2] Please see Enbridge Gas's historical scorecard results for 2014 to 2023 at Attachment 1. The years 2019 to 2023 are for Enbridge Gas, whereas 2014 to 2018 are presented separately for the pre-amalgamated utilities.

8. Enbridge Gas believes that the 20 performance measures across the four categories set out in the scorecard established during the MAADs proceeding continue to be appropriate, including the 8 measures that are prescribed by the GDAR, subject to Enbridge Gas's proposal for the MRPM in this evidence.

9. Enbridge Gas requests approval of the continued use of the existing scorecard, with the proposed modification to the calculation of MRPM as described in this evidence.

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[2] EB-2023-0092.

1.2 Meter Reading Performance Measurement Target

10. In Phase 1 of the Application, Enbridge Gas requested a partial exemption for three performance standard metrics, one of which is the MRPM, beginning in 2024 for the rebasing period or until the OEB orders otherwise. Enbridge Gas proposed that no more than 2% of meters have a consecutive estimate for four months or more.

11. The MRPM is calculated as the total number of meters without a meter read for four consecutive months or more, divided by the total number of active meters to be read. This measurement shall not exceed 0.5% on a yearly basis. The metric does not consider why Enbridge Gas has not read a meter.

12. Enbridge Gas cited various reasons for not meeting the MRPM in EB-2022-0200 Exhibit 1, Tab 7, Schedule 1, page 10. In 2019, the main reasons for not meeting the target included extreme weather conditions and a key vendor exiting the meter reading market and ending its contract with Enbridge Gas. In 2020 and 2021, additional challenges tied to the pandemic prevented Enbridge Gas from meeting the MRPM, and this included public concerns about the safety of meter reading activities, closed businesses, increased customer sensitivities and access issues.

13. In the Phase 1 Decision, the OEB denied the exemption request to change the MRPM target to 2% of meters, maintaining the 0.5% target.[3] Further, the OEB noted, “changing the metric to 2% would lock in the adverse performance levels that occurred in unusual circumstances. The OEB finds that there are no unusual circumstances persisting in 2023, beyond Enbridge Gas’s control.”[4]

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[3] EB-2022-0200 Decision and Order, December 21, 2023, p. 135.
[4] Ibid.

14. With respect, Enbridge Gas's evidence shows that in fact, these unusual circumstances are persisting in 2023 and 2024 and they are expected to continue into the foreseeable future. This has and will continue to significantly impact the ability of Enbridge Gas to meet the MRPM target. Meter access issues are especially concerning as gaining access is beyond the control of Enbridge Gas where customers do not respond to Enbridge Gas's reasonable attempts to gain access or obtain a reading directly from the customers. Until these customers provide Enbridge Gas with access to the meter or service is discontinued at these premises, these inaccessible meters remain as part of the total number of unread meters. Unless the OEB allows Enbridge Gas to remove these inaccessible meters from the unread meter total, the effect is that Enbridge Gas will continue to be penalized for customer behaviour that is beyond the control of Enbridge Gas. This is neither fair nor appropriate.

15. Enbridge Gas anticipates that some parties may take the view that Enbridge Gas should have requested a review of the OEB's Phase 1 Decision with respect to the MRPM exemption. To the contrary, Enbridge Gas believes that it is more appropriate and efficient to make this updated proposal as part of Phase 2 of this proceeding, given the scope of the performance scorecard issue in Phase 2 and the fact that Enbridge Gas continues to experience extraordinary meter access issues despite its extensive mitigation efforts.

2. Meter Reading Performance Metric Proposal

2.1. Proposal

16. Enbridge Gas proposes to continue the current metrics and measurement targets from 2024 to 2028, with the exception of the calculation of the MRPM metric, which falls under the customer focus category. Enbridge Gas is not challenging the OEB's

Phase 1 Decision to maintain the 0.5% target, however, the Company does not agree that inaccessible meters should be included in the calculation of the metric. Enbridge Gas is proposing that all meters with access issues caused by or within the control of the customer to address be excluded from the MRPM calculation for the purposes of the scorecard measure. Enbridge Gas therefore defines inaccessible meters as those meters to which the Company has not been able to obtain access to read the meter for 4 or more consecutive months because of customer-driven conditions that are beyond Enbridge Gas's control.

17. Enbridge Gas acknowledges that in effect, this proposal could be viewed as an exemption request under Section 1.5.1 of the GDAR related to the MRPM. In this case, because evidence shows that the inaccessible meters are beyond the control of Enbridge Gas even through active mitigation efforts, it is appropriate for Enbridge Gas to make this request in relation to this issue in Phase 2. It is simply not fair for the OEB to hold Enbridge Gas accountable for customer behaviour that amounts to denying access to read the meter.

18. It is a term in the Enbridge Gas Conditions of Service for both rate zones that the customer shall provide access to Enbridge Gas to read the meter and failure to do so may result in the discontinuation of service.[5] It is within the authority of Enbridge Gas to discontinue service in these circumstances, subject to the disconnection requirements set out in the GDAR and the Conditions of Service. In some instances, it may be necessary for Enbridge Gas to eventually take this step. However, consistent with the OEB's restrictions related to service disconnection (e.g., disconnection ban during the winter season), Enbridge Gas will only resort to

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[5] Enbridge Gas Inc. Conditions of Service. https://www.enbridgegas.com/Conditions-of-Service. Section 4.5, p.7.

service disconnection as a last resort and will provide clear communication to the customer prior. If the OEB were to take a very strict view of the MRPM and not accept Enbridge Gas's proposal to remove inaccessible meters from the calculation of unread meters, Enbridge Gas may need to conduct additional service disconnections just to have a better chance of meeting the MRPM. This would be inefficient at best and would not be in the best interests of customers.

2.2. Rationale

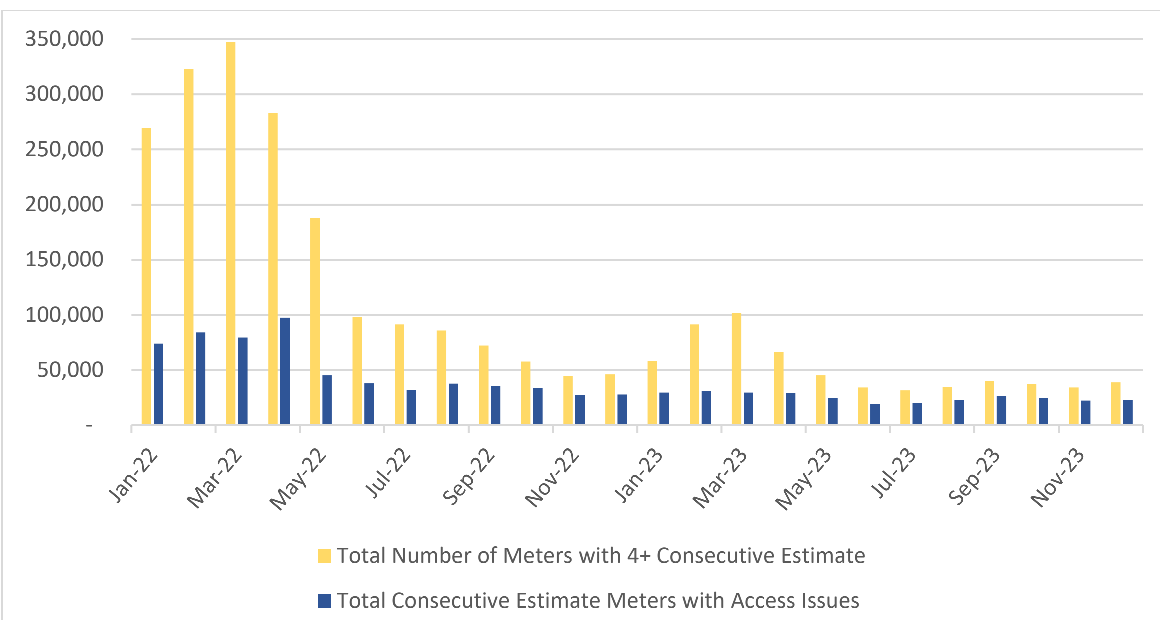
19. Enbridge Gas is inherently motivated to obtain actual customer meter reads on a regular basis and has taken all reasonable steps in striving to achieve the SQR target for MRPM on a consistent basis. Despite that, there continues to exist unusual persisting circumstances beyond Enbridge Gas's control that limit the ability for meter readers to access a certain proportion of gas meters to conduct consistent reads, which contributed to missing the target for the MRPM in 2022 and 2023.

20. While the number of overall consecutive meters not read continues to decrease, the number of those attributable to access issues, which are beyond Enbridge Gas's control, has risen. Attachment 2, page 1, column (d) and (j) show the number of consecutive estimate meters that are attributable to inaccessible meters from 2022 to 2023. Customer related access issues accounted for 49% of missed reads in 2023 as shown at Attachment 2, page 1, column (l), line (13), an increase from 32% in 2022 as shown in Attachment 2, page 1, column (f), line (13). With approximately 3.9 million customers, to meet an MRPM metric of 0.5%, no more than 19,000 meters can have 4 or more months of consecutive estimates, or the metric will not be achieved. If meters with access issues are removed from the MRPM calculation, the metric achieved for 2022 would be 2.78% instead of 4.10%,

and in 2023, the metric would be 0.66% instead of 1.31%.

21. Access issues are further compounded by seasonality. While Enbridge Gas has historically met the required MRPM while managing unpredictable winter impacts, when combined with the rising access issues, it is creating a situation in which Enbridge Gas cannot recover quickly enough to correct the metric throughout the remainder of the year. Figure 1 illustrates how seasonality compounds existing access issues. Historically, Enbridge Gas has been able to use the summer months to catch up on reads and correct the overall MRPM by year-end. However, as access issues increasingly account for the reasons for consecutive estimates in the summer months, the MRPM metric has become increasingly more difficult to achieve. As provided at Attachment 2, page 1, in summer months access issues accounted for 45% of consecutive estimates in 2022 and this increased to 66% in 2023, while in the winter months that is 19% and 37% respectively.

Figure 1: Impacts of Seasonality on Consecutive Estimates



22. Given that MRPM is a cumulative calculation, seasonal impacts combined with increasing access issues make it difficult to improve the metric year-over-year. The MRPM from the end of 2023 is carried into 2024 and Enbridge Gas will start the year at 1.3%. As the total number of unread meters fluctuates, some meters are read and subtracted from the totals, while other meters remain as unread from the previous month, and new meters reach their 4-month timeline and are added to the current consecutive estimate results. This means that even though a percentage of meters have successfully been read, Enbridge Gas will continue to have meters that have consecutive estimates. In addition, if Enbridge Gas experiences one or two challenging months for meter reading during a year, this makes the MRPM difficult to achieve, and it becomes impossible to catch up to the metric and meet the target for the remainder of the year. For example, readers have 3 days to read their routes within the billing cycle. When 1 reader is absent (illness or otherwise) they will miss routes for 2 to 3 cycles (5000 to 10,000 reads). Unread meters being carried into the next year compound the results when added to the external challenges such as access, customer sensitivity, and staffing issues.

23. Enbridge Gas's MRPM going into 2024 was 1.3%. The first quarter of 2024 has had favourable weather conditions which has allowed Enbridge Gas to reduce the overall MRPM to 1.2%.

24. Despite a 74% improvement in MRPM over the past two years, Enbridge Gas anticipates continued challenges in meeting the 0.5% GDAR requirement for 2024 given the persisting access issues caused by changes in post-pandemic customer behaviour and the cumulative calculation of MRPM. Even with inaccessible meters removed from the total unread meters count, Enbridge Gas anticipates the 2024 MRPM will be between 0.5% and about 0.6%. Meeting the 0.5% target is still a stretch for Enbridge Gas under known conditions. Attachment 2, page 2, is a 2024

Forecast of MRPM for Enbridge Gas. For the foreseeable future beyond 2024, Enbridge Gas expects that it will still require ongoing mitigation efforts and attention to approach and aim to meet the 0.5% MRPM target, even with inaccessible meters excluded from the total unread meter count. Accordingly, Enbridge Gas seeks to remove inaccessible meters for the entirety of the IR term.

2.3. Types of Access Issues

25. Below is a description of the various types of customer-related access issues that prevent Enbridge Gas from conducting regular meter reads including:
    a) Locked gates and inside meters;
    b) Customer sensitivity; and
    c) Obstruction.

Attachment 3 contains images that illustrate access issues.

Locked Gates and Inside Meters

26. Meter readers experienced an increase in locked gates as a result of an increase in customer swimming pools during the pandemic. In 2021, Ontario saw an increase in swimming pool permits of 33%.[6] The increase in swimming pools resulted in an increase in locked fences, as required by the Swimming Pool Safety Act[7] and/or municipal by-laws. Since gas meters are usually located in backyards, the presence of pools and new fences prevent meter readers from accessing the gas meters to obtain meter reads. Customers are also adding locks to their gates as increasing

[6] Municipal Property Assessment Corporation. (2022 May 3). Backyard pools make a splash with Ontario property owners. MPAC. https://www.mpac.ca/en/News/OurStories/BackyardpoolsmakesplashOntariopropertyowners
[7] Office of Assembly. (2006). Bill 74, Swimming Pool Safety Act. Legislative Assembly of Ontario. https://www.ola.org/en/legislative-business/bills/parliament-38/session-2/bill-74.

crime rates are raising concern about personal safety and with an increase of dog ownership.

27. Enbridge Gas has seen a significant increase in business closures and the number of vacant properties, since 2021. Initially, this was related to the pandemic and lockdown measures, but the trend has continued to increase recently as a result of inflation.[8] Meter readers are not able to gain access to read meters inside of vacant premises.

Customer Sensitivity

28. Over the past few years, with increasing crime, customer presence (working from home) and installation of home cameras, Enbridge Gas has seen a rise in customers refusing access onto their property. This prevents Enbridge Gas from obtaining a meter read. More customers than ever before are calling the Enbridge Gas Call Centre to confirm the legitimacy of meter readers on their property or to request that readers refrain from entering their property. Toronto has seen a surge of 24.7% in auto thefts and 25.3% in property break and enters in 2023.[9] Enbridge Gas continues to try and educate customers on the meter reading process, but many customers still do not realize that Enbridge Gas meter readers need to physically see the meter to read it (and conduct a safety inspection). There is a misconception that the gas meter can be read remotely like water/hydro meters. Only 3.8% (143,000) of Enbridge Gas meters have an Encoder Received Transmitter (ERT) meter and can be read remotely. Further details on ERT meters can be found in paragraph 39 of this evidence.

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[8] Better Dwelling (2023 September 25). Canadian Business Closures Surge, Fewest Business Openings Since Lockdowns. https://betterdwelling.com/canadian-business-closures-surge-fewest-business-openings-since-lockdowns/

[9] Toronto Police Service Public Safety Data Portal. (2024 April 4). Data Analytics | Toronto Police Service Public Safety Data Portal I https://data.torontopolice.on.ca/pages/data-analytics

Obstructions

29. There has been an increasing presence of dogs since the beginning of the pandemic in Ontario.[10] Safety continues to be the top priority and a core value of Enbridge Gas and there have been increasing concerns around dog bites and the potential for dogs to escape when a reader tries to enter the yard. If a dog is present in the yard, and the reader does not feel safe entering, they will knock on the customer's door and ask that they put the dog in the house or provide a read themselves. An increase in the number of customers working from home post-pandemic has also led to a rise in the number of dogs outside during the day, when readers attempt to read meters. As readers encounter more dogs, there is a greater potential for dog bites. If a meter reader cannot enter the premise safely, the meter is unread as a result. Safety continues to be a core value for Enbridge Gas and its vendor partners. Together they mitigate any potential risk that may result in a reported safety incident. The Green Book,[11] enforced by the Ontario Ministry of Labor, provides a guideline for workplace environments that Enbridge Gas and its vendors must adhere to in order to ensure employee safety. Meter readers will not enter a premise when there is a situation that could result in injury.

30. Other types of obstruction to the meter include foliage, stored materials, tools, equipment, construction, excessive build up of garbage, and animal waste. During the pandemic, there was an increase in home projects overall, including structures that customers have built around gas meters that limit access such as decks, hot tubs, and sheds. There are also instances where a meter is inaccessible due to overgrowth of plants/foliage, shrubs, and trees, which could also be poisonous, or

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[10] Veterinary Practice News Canada (2022 February 15). Canadians Adopted Three Million Pets Amidst Pandemic. Kenilworth Media. https://www.veterinarypracticenews.ca/canadians-adopted-three-million-pets-amidst-pandemic/

[11] Navigating the Green Book (OHSA). https://osg.ca/navigating-the-ohs-act-a-how-to-guide

gardens built around the gas meter. Ice and snow can obstruct access to the gas meter through either an unsafe path or by blocking the opening of a gate to a backyard. Gas meters are typically placed in discreet locations, exposing meter readers to safety risks of slips, trips, and falls. Snow can create additional hazards if it blocks gates or covers window wells next to gas meters. It is the customer's obligation to keep their gas meter free from obstruction according to the Conditions of Service.[12] Please see Attachment 3 for photos of obstruction captured by meter readers.

3. Mitigation

3.1 Past Mitigation Measures

31. It is in the best interest of the customer as well as Enbridge Gas to obtain meter reads. Customers taking a self-read and providing it to Enbridge Gas or allowing Enbridge Gas to access the meter and capture the read is how Enbridge Gas obtains reads currently. This process ensures that customers gas bills are accurate on a monthly basis. Enbridge Gas continues to send reminder communications to customers asking for access to read the meter or to provide their meter reading by phone or online. Over the past two years, Enbridge Gas has undertaken several extraordinary mitigation measures and incurred additional expense to counteract the meter reading constraints and potential impacts on customer billing. These include increased staffing and improvements in processes and technology. Enbridge Gas has also increased customer outreach and marketing communications to improve the MRPM results. Overall, these measures have led to reduction in MRPM of 74% from 5.0% in 2021 to 1.3% for 2023. Attachment 2, page 1, provides a breakdown of MRPM results for 2022 to 2023.

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[12] Enbridge Gas Inc. Conditions of Service. https://www.enbridgegas.com/Conditions-of-Service. Section 4.5, p.7.

Staffing Increases

32. Enbridge Gas is involved in continuous review of staffing to ensure active hiring occurs wherever necessary to normalize staffing levels. Since March 2022, the number of meter reading staff has increased by 12.5%. In December 2019, the long-standing meter reading vendor in the Union rate zones terminated its contract with Enbridge Gas and a new vendor was acquired, with no prior experience reading meters. Over the pandemic, both vendors struggled to retain meter readers, given safety concerns and labour shortages. Since March 2022, meter reading staff for the new vendor has increased by 18%. This correlates to an improvement in MRPM for Union rate zones from 7.65% in 2020 to 1.68% in 2023. Overall attrition rates went from 40% in 2020 to 27% in 2022 with a further decrease to 23% in 2023.

33. Enbridge Gas has assisted meter reading vendors with recruitment activities and hiring practices. While hiring and attrition rates have improved over the past two years, this industry continues to struggle to find reliable resourcing, particularly in the winter months for rural, remote, and Northern areas. Incentives have been offered to meter readers for working extended hours during evenings and weekends.

Process Improvements

34. Enbridge Gas monitors the meter reading process daily to ensure all reads are captured and used for billing.

35. Enbridge Gas has regularly scheduled meetings with meter reading vendors to review performance, identify gaps and mitigate anticipated obstacles to improve MRPM. For the newer vendor, having these regular touchpoints have resulted in

meter reading improvements to the point that they are now performing at the same level as the long-standing vendor.

36. Additionally, Enbridge Gas has updated internal processes so that Call Centre agents review the meter reading history every time that a customer calls so that they can try to obtain a meter read (or schedule a read appointment if required) and address any potential access issues.

Technology Improvements

37. Enbridge Gas has created a new webpage[13] that allows customers to submit a meter read without requiring or accessing a MyAccount profile. Customers simply require their account number and postal code.

38. In late 2023, new handheld technology was implemented for use by the meter readers. The new handheld devices have real time upload capabilities resulting in extended reading hours. With the earlier model handhelds, meter readers had to physically be in an Enbridge/vendor office to upload the reads from the meter reading routes. The new ones allow the upload from anywhere, at anytime. They are also much lighter to carry and easier to use.

39. The meter reading team within Enbridge Gas has worked with the Operations team to target meter exchanges for installation of ERT meters, where appropriate. This includes installing ERT meters on specific properties that have historical access issues and replacing damaged and broken meters. ERT meters use a low powered radio frequency to communicate with the hand-held device used by meter readers

[13] Enbridge Gas Inc., Submit Meter Reading, https://myaccount.enbridgegas.com/My-Account/My-Gas-Meter

but must be read near the physical location of the meter. ERT does allow Enbridge Gas to obtain a meter reading within close proximity of the meter. However, as a result of the significant supply chain issues and cost implications, more wide-spread use of ERT meters is not practical. Additionally, Enbridge Gas requires access to the meter in order to install an ERT, meaning the access challenges pose a barrier to more extensive ERT installation.

40. Enbridge Gas is also considering Advanced Metering Infrastructure (AMI) for the meter reads. AMI uses a two-way signal that allows for real-time meter reads that can be obtained without a physical presence. As directed by the OEB in the Phase 1 Decision,[14] Enbridge Gas will file an update on the AMI pilot project in Phase 3.

Marketing/Outreach

41. Enbridge Gas increased its customer outreach activities to obtain a meter reading or schedule an appointment to attend the property. Outreach has included dialer campaigns and meter reading contests targeting customers with access issues related to overgrown vegetation, dogs, or locked gates. Enbridge Gas ran campaigns where Call Centre agents called customers over the weekend to schedule appointments to read meters.

42. Enbridge Gas has been running digital contests to increase the number of meter reads submitted by customers, which has been largely successful. The average number of monthly reads submitted by customers has increased by 115% from 2021 to 2023.

[14] EB-2022-0200, Decision and Order, December 21, 2023, p. 135.

Table 1

Number of Meters – Customer Read

Line No.	Particulars	2021	2023	Percentage Change
1	Agent entered customer read	2,905	3,114	7%
2	Customer submitted read (Interactive Voice Response)	5,245	7,887	50%
3	Customer submitted read (Web)	45,297	103,875	129%
4	Total	53,446	114,876	115%

43. Despite the effectiveness of these campaigns in obtaining meter reads, it has not significantly improved the MRPM target because the customers who are providing their own meter read through the campaigns are also the customers for whom Enbridge Gas meter reading vendors are able to obtain a reading. Customers with meter access issues have the same difficulty accessing the meter as meter readers. If there is a deck or a shed in front of the meter, the customers will not be able to obtain the read to submit it themselves.

44. Enbridge Gas is working on a plan to educate customers about the use of actual reads. There is a misconception that Enbridge Gas does not use a customer provided read because if the read is provided outside of the three-day meter reading window, the bills display ‘estimate’ read where an ‘actual’ meter read was obtained within the billing month. These reads are in fact used to adjust the account, as required, and are used to estimate the read that is within the reading window to generate the bill. Enbridge Gas is considering a process improvement to address how reads are utilized based on when they are received and how they are presented on the bill.

3.2. Mitigation Plan

45. Enbridge Gas is committed to providing excellent customer service to all customers and has developed mitigation plans for the performance measures not met in 2021. The mitigation plans outline the approach to improve metric performance: the mitigation plans for MRPM and CASL were provided to the OEB as part of the Assurance of Voluntary Compliance[15] dated September 2022 and the mitigation plans provided at EB-2022-0200 Exhibit 1, Tab 7, Schedule 1, Attachments 2 to 4 additionally included Time to Reschedule a Missed Appointment (TRMA) for 2022 and beyond.

46. The 2024 MRPM Mitigation Plan was developed by reviewing previous mitigation plans to determine which strategies implemented contributed to the improvements to the MRPM metric. The mitigation plan was developed by the Customer Care group with input from various internal groups such as Operations, Technology, and Marketing. Additionally, Enbridge Gas engaged meter reading vendors on a regular basis for further input to improve the MRPM. The 2024 MRPM Mitigation Plan provided at Attachment 4 was provided to OEB staff on March 8, 2024.

47. The MRPM Mitigation Plan for 2024 includes plans for continuous staffing improvements, marketing campaigns that include customer education about the use of meter reads and importance of ensuring clearance of the meter, process improvements, and technology updates that improve overall system functionality and use of meter reads.

48. Enbridge Gas is committed to continuous year-over-year performance improvement and has developed its mitigation plans to aid in achieving continuous

[15] EB-2022-0188, Assurance of Voluntary Compliance, September 12, 2022. https://www.oeb.ca/sites/default/files/EGI-Assurance-of-Voluntary-Compliance-20220912.pdf

progress. Despite its best efforts, Enbridge Gas remains concerned that the MRPM as it stands is simply not achievable even through extraordinary and consistent efforts from Enbridge Gas and its meter reading contractors. This should be acknowledged through acceptance of the above proposal to remove the burden of inaccessible meters from the unread meter count for the purposes of calculating the MRPM performance metric.

EGI OEB Scorecard 2014 - 2023

#	Performance Measure	Target	Actual	Actual	Actual	Actual	Actual	Actual		Actual		Actual		Actual		Actual	
			2023 EGI	2022 EGI	2021 EGI	2020 EGI	2019 EGI	2018 EGD	2018 UNION	2017 EGD	2017 UNION	2016 EGD	2016 UNION	2015 EGD	2015 UNION	2014 EGD	2014 UNION
#	**CUSTOMER FOCUS (Service Quality & Customer Satisfaction)**																
1	**Reconnection Response Time (# of days to reconnect a customer)** (# of reconnections completed within 2 business days/# of reconnections completed)	85.0%	99.3%	98.1%	96.9%	98.9%	98.1%	97.3%	90.7%	96.2%	90.5%	93.8%	86.2%	94.6%	90.1%	94.0%	91.9%
2	**Scheduled appointments met on time (appointments met within designated time period)** (# of appointments met within 4hrs of the scheduled date/# of appointments scheduled in the month)	85.0%	96.3%	95.4%	94.5%	98.8%	98.5%	94.7%	98.8%	94.3%	99.0%	94.8%	98.9%	95.2%	98.8%	95.1%	97.7%
3	**Telephone calls answered on time (call answering service level)** (# of calls answered within 30 seconds / # of calls received)	75.0%	89.5%	75.9%	64.3%	75.2%	79.0%	82.0%	77.6%	82.5%	79.2%	82.4%	80.1%	79.7%	79.1%	79.0%	73.6%
4	**Customer Complaint Written Response (# of days to provide a written response)** # of complaints requiring response within 10 days / # of complaints requiring a written response	80.0%	100.0%	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	95.5%	100.0%	100.0%	100.0%	93.3%	100.0%
5	**Billing accuracy** 'The requirement states that utilities should complete manual checks of their bills to verify data when a meter read demonstrates excessively high or low usage.'		331,489 manual checks completed as per QAP	390,246 manual checks completed as per QAP	384,858 manual checks completed as per QAP	427,524 manual checks completed as per QAP	429,386 manual checks completed as per QAP	224,316 manual checks completed as per QAP	218,700 manual checks completed as per QAP	494,330 manual checks completed as per QAP	167,075 manual checks completed as per QAP	453,326 manual checks completed as per QAP	171,381 manual checks completed as per QAP	478,248 manual checks completed as per QAP	173,132 manual checks completed as per QAP	462,936 manual checks completed as per QAP	154,888 manual checks completed as per QAP
6	**Abandon Rate (# of calls abandon rate)** (# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent)	10.0%	1.4%	7.1%	16.0%	5.4%	2.50%	1.9%	2.6%	1.8%	3.4%	1.8%	3.6%	2.4%	4.0%	1.9%	4.7%
7	**Time to Reschedule Missed Appointments** (% of rescheduled work within 2 hours of the end of the original appointment time)	98.0%[1]	97.8%	93.8%	97.0%	97.3%	97.0%	98.7%	99.8%	96.8%	99.9%	94.2%	99.8%	94.8%	99.8%	95.5%	99.9%
	OPERATIONAL EFFECTIVENESS (Safety, System Reliability, Asset Management & Cost Control)																
8	**Meter Reading Performance** # of meters with no read for 4 consecutive months / # of active meters to be read	0.5%	1.3%	4.1%	5.0%	4.4%	0.7%	0.5%	0.4%	0.5%	0.1%	0.4%	0.1%	0.5%	0.2%	0.7%	0.4%
9	**% of Emergency Calls Responded within One Hour** (# of emergency calls responded within 60 minutes / # of emergency calls)	90.0%	95.3%	94.1%	95.2%	96.7%	96.7%	96.6%	99.3%	96.8%	99.0%	96.1%	98.8%	96.7%	98.6%	96.9%	97.8%
10	**Compression Reliability** % reliable for transmission compression		100.0%	100.0%	99.7%	99.7%	99.9%	NA	99.8%	NA	99.9%	NA	99.7%	NA	99.8%	NA	99.9%
11	**Damages per 1000 locate requests**		2.10	2.31	1.95	2.22	1.97	1.85	2.28	1.83	2.17	2.19	2.41	2.46	2.56	2.49	2.67
12	**Total Cost per Customer** ($ / Customer)		745.7	683.2	643.9	658.2	653.6	530.7	756.7	513.9	730.3	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]
13	**Total Cost per km of Distribution Pipe** ($ / km of Distribution Pipe)		19,079.6	17,480.7	16,639.6	16,928.5	16,735.4	15,123.1	16,947.5	14,739.7	16,109.4	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]
	PUBLIC POLICY RESPONSIVENESS (Conservation & Demand Management & Connection of Renewable Generation)																
14	**Total Cumulative Cubic Meters of Natural Gas Saved (Net)** (Millions)		NA[3]	N/A[4]	1,707.5[5]	1,632.2	2,075.9	807.5	1,124.5	787.2	1,182.7	837.1	959.4	826.2	1,750.8	719.8	1,889.5
	FINANCIAL PERFORMANCE (Financial Ratios)																
15	**Current Ratio** (Current Assets / Current Liabilities)		0.92	0.84	0.71	0.66	0.75	0.93	0.69	0.84	0.47	0.7	0.64	0.87	0.77	0.65	0.81
16	**Debt Ratio** (Total Debt / Total Assets)		0.39	0.42	0.41	0.40	0.40	0.49	0.51	0.47	0.49	0.47	0.47	0.47	0.48	0.49	0.45
17	**Debt to Equity Ratio** (Total Debt / Shareholders' Equity)		0.97	1.10	1.06	1.01	0.98	1.67	2.12	1.54	2.08	1.48	2.06	1.59	2.08	1.69	2.12
18	**Interest Coverage** (EBIT / Interest Charges)		1.75	2.54	2.55	2.34	2.53	2.52	2.69	1.96	2.42	2.07	2.33	2.18	2.33	2.3	2.46
19	**Financial Statement Return on Assets** (Net Income / Total Assets)		1.20%	2.03%	2.07%	1.97%	2.25%	2.98%	3.20%	2.27%	2.71%	2.26%	2.58%	2.38%	2.70%	2.60%	2.87%
20	**Financial Statement Return on Equity** (Net Income / Shareholders' Equity)		3.00%	5.37%	5.32%	4.96%	5.56%	10.20%	13.25%	7.39%	11.43%	7.17%	11.39%	8.00%	11.71%	8.99%	13.43%

[1] Time to Reschedule Missed Appointment target was 100% prior to the Phase 1 Decision
[2] 2014 through 2016 results are not available as the metrics were not historically tracked by EGD or Union
[3] 2023 is in draft
[4] 2022 results will be available in 2024
[5] 2021 results are audited and approved in the DSM Clearance Proceeding

2022-2023 Enbridge Gas Meter Reading Results

		2022						2023					
Line No.	Particulars	Actual Number of Meters	Total Number of Consecutive Estimate Meters (1)	% of Target Achieved	Total Number of Inaccessible Meters	% of Target Achieved (Inaccessible Meters removed)	% of Inaccessible Meters to Total Number of Consecutive Estimate Meters	Actual Number of Meters	Total Number of Consecutive Estimate Meters (1)	% of Target Achieved	Total Number of Inaccessible Meters	% of Target Achieved (Inaccessible Meters removed)	% of Inaccessible Meters to Total Number of Unread Meters
		(a)	(b)	(c) = (b / a)	(d)	(e) = (b - d) / (a)	(f) = (d / b)	(g)	(h)	(i) = (h / g)	(j)	(k) = (h - j) / (g)	(l) = (j / h)
1	Jan	3,852,254	269,595	7.00%	73,947	5.08%	27.4%	3,895,714	58,357	1.50%	29,526	0.74%	50.60%
2	Feb	3,855,304	322,767	8.37%	84,237	6.19%	26.1%	3,898,223	91,495	2.35%	30,996	1.55%	33.88%
3	Mar	3,859,120	347,351	9.00%	79,438	6.94%	22.9%	3,900,498	101,747	2.61%	29,487	1.85%	28.98%
4	April	3,862,735	282,900	7.32%	97,548	4.80%	34.5%	3,902,609	66,268	1.70%	28,987	0.96%	43.74%
5	May	3,866,109	187,842	4.86%	45,332	3.69%	24.1%	3,904,701	45,364	1.16%	24,711	0.53%	54.47%
6	June	3,869,012	98,078	2.53%	38,130	1.55%	38.9%	3,906,620	34,113	0.87%	19,295	0.38%	56.56%
7	July	3,871,755	91,365	2.36%	31,801	1.54%	34.8%	3,908,952	31,565	0.81%	20,307	0.29%	64.33%
8	Aug	3,874,809	85,834	2.22%	37,598	1.24%	43.8%	3,910,830	34,873	0.89%	22,996	0.30%	65.94%
9	Sept	3,878,489	72,168	1.86%	35,637	0.94%	49.4%	3,912,655	40,191	1.03%	26,287	0.36%	65.41%
10	Oct	3,883,537	57,689	1.49%	34,089	0.61%	59.1%	3,914,871	37,179	0.95%	24,726	0.32%	66.51%
11	Nov	3,888,916	44,432	1.14%	27,692	0.43%	62.3%	3,917,430	34,250	0.87%	22,422	0.30%	65.47%
12	Dec	3,892,705	46,060	1.18%	27,982	0.46%	60.8%	3,919,099	38,903	0.99%	23,049	0.40%	59.25%
13	Total	46,454,745	1,906,081	4.10%	613,431	2.78%	32.2%	46,892,202	614,305	1.31%	302,789	0.66%	49.29%
14	Winter Mths (Sum of line 1 to 4) (2)		1,222,613		237,622		19%		317,867		118,996		37%
15	Summer Mths (Sum of line 7 to10) (2)		307,056		139,125		45%		143,808		94,316		66%

Notes:

(1) An unread meter is a meter with over 4 months of consecutive estimates.

(2) Meters are not included in the calculation of MRPM until they have had at least 4 months of no reads. For this reason, impacts from Winter months start to show up in Jan-April (Meters that couldn't be read for 4+ months starting in Oct. to Jan.) and summer months include July-Oct. (Meters that couldn't be read for 4+ months starting in Apr. to July).

2024 Forecast

Line No.	Particulars	Estimated Number of Meters	Total Number of Consecutive Estimate Meters (1)	% of Target Achieved	Total Number of Inaccessible Meters	% of Target Achieved (Inaccessible Meters removed)	
		(a)	(b)	(c) = (b / a)	(d)	(e) = (b - d) / (a)	
1	Jan	3,920,081	50,495	1.29%	25,164	0.64%	(2)
2	Feb	3,942,855	51,575	1.30%	24,295	0.62%	(2)
3	Mar	3,945,357	49,312	1.20%	22,272	0.56%	(2)
4	Apr	3,947,468	51,443	1.30%	25,722	0.65%	
5	May	3,949,560	47,904	1.20%	23,952	0.61%	
6	Jun	3,951,479	36,023	0.90%	18,012	0.46%	
7	Jul	3,953,811	33,333	0.80%	16,666	0.42%	
8	Aug	3,955,689	36,826	0.90%	18,413	0.47%	
9	Sep	3,957,514	34,522	0.90%	17,261	0.44%	
10	Oct	3,959,730	36,621	0.90%	18,311	0.46%	
11	Nov	3,962,289	36,168	0.90%	18,084	0.46%	
12	Dec	3,963,958	38,442	1.00%	19,221	0.48%	
13	Total	47,409,791	502,664	1.06%	247,372	0.52%	

Notes:
(1) An unread meter is a meter with over 4 months of consecutive estimates.
(2) Jan. to Mar. are actuals.

Images of Inaccessible Gas Meters Due to Obstructions

Meters obstructed by locked gates

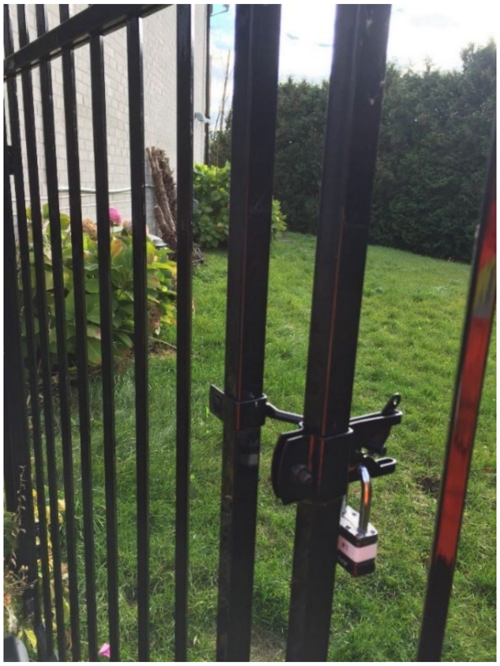

Image 1

Image 2

Meters obstructed by physical barriers

Image 3

Image 4

Image 5

Meters obstructed by physical structures

Image 6

Image 7

Image 8

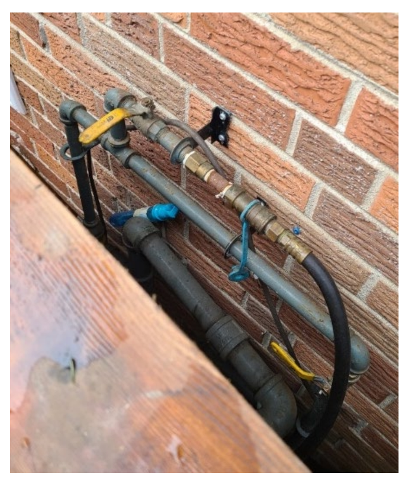

Image 9

Image 10

Image 11

Meters obstructed by overgrown foliage

Image 12

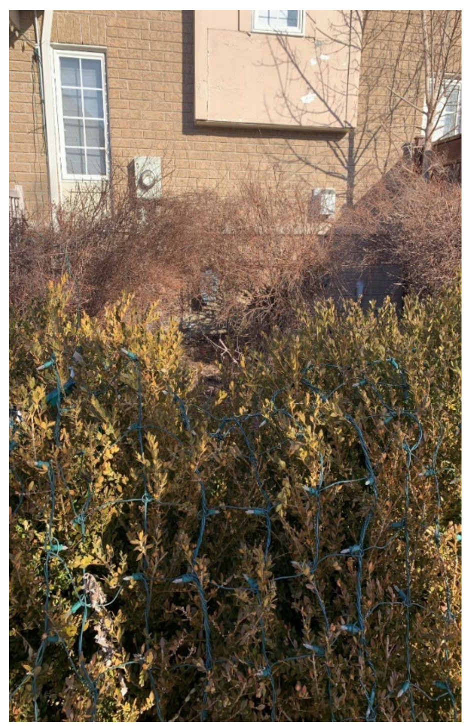

Image 13

Meters obstructed by snow

Image 14

Image 15

Meters obstructed from safety concerns

Image 16

Image 17

Customer Care

Meter Reading Performance

Enbridge Gas Inc.
Mitigation Plan

February 28, 2024

Mitigation Plan – Consecutive Estimated Meter Reads

Background

The meter reading performance measurement (MRPM) metric has been challenging for Enbridge Gas Inc. (Enbridge Gas) to achieve for several reasons. MRPM is a cumulative metric whereby the total number of unread meters fluctuates as some meters are read and come off the totals, while other meters remain as unread from the previous month, and new meters reach their 4-month timeline and are added to the current consecutive estimate results. This means that even though a percentage of meters have successfully been read, Enbridge Gas will continue to have meters that have consecutive estimates. With over 3.8 million customers, if 19,000 meters have consecutive estimates on average each month the metric is not achieved. With bi-monthly meter reading, once a meter has a consecutive estimate that is 4+ months (two-meter reading cycles), it will count toward the metric in a minimum of two months. The decision of a key meter reading vendor (serving 40% of Enbridge Gas's customers) to no longer provide meter reading service and end its contract, resulting in the unplanned need to hire and onboard a new vendor at the end of 2019. Since the start of 2020, the COVID-19 (Covid) pandemic has presented many additional challenges to meeting the MRPM, such as:

- The Covid pandemic resulting in closed businesses, increased customer sensitivity over contact with meter readers, access issues such as inability to read inside meters, During the early onset of Covid and periods of lockdown, Enbridge Gas faced several challenges around meter reading and had considered pausing meter reading activity due to questions from the public and law enforcement around the safety of meter reading activity. Enbridge Gas directed its meter reading partners to ensure that all staff were working as safely as possible and to avoid close contact with the public and customers based on the sensitivity of the Covid pandemic;

- Extreme weather events such as freezing rain, polar vortex, heavy snowfall, and flooding which limited the ability to travel to properties and access meters safely;

- A new vendor was still transitioning and learning the business, while also facing challenges with staffing due to the Covid pandemic. Resourcing issues included challenges hiring staff and absences due to illness and the quarantine/isolation periods required by Public Health to ensure public safety; and

- Challenges with access continue in 2024 due to a change in customers' behaviour. The number of pets has increased as well as new pool installations that have caused gates to be locked and meters to be inaccessible. With more customers working from home, dogs are outside in the yard more often. The public is also cautious of allowing people on their property given the increase in violence, crimes and break-ins. Enbridge has seen an increase in inquiries to confirm that a meter reader visited their home and more customer confrontation with readers, ultimately denying access or threatening to call police. In 2022, customer related access issues made up on average 20% of the total consecutive count and in 2023 this has risen to 39% in 2023.

The MRPM metric of 0.5% is a very onerous Service Quality Requirement (SQR) for Enbridge Gas to meet given its geographic reach, especially when complicated by extraordinary events such as extreme weather, changes in customer behaviour and the many impacts from the Covid pandemic, which continue to be unusual persisting circumstances in 2024. At the current metric level, based on access issues alone, Enbridge Gas is not able to meet the metric. In addition, if Enbridge Gas experiences a challenging one or two months for meter reading during a year, the MRPM is so difficult to achieve that it becomes impossible to meet for the year. For example, readers have 3 days to read their routes within the billing cycle. If 1 reader is absent from work (illness or otherwise) they can miss routes for 2 to 3 cycles (5000-10,000 reads). Another example impacting meter reading was the month-long Ottawa convoy protest. This made getting around the Ottawa area very difficult which resulted in approximately 26,000 meter reads missed.

Mitigation Plan for 2024 – Consecutive Estimate Meter Reads

Enbridge Gas recognizes the importance of conducting regular meter reads. The 2023 mitigation activities resulted in a 68% improvement in the metric. Enbridge Gas will continue to perform these activities and will seek additional opportunities to implement further improvements. The following steps will be taken to ensure meter reads are continuously attained.

<table>
<tr><th>Initiative</th><th>Description</th><th>Target Segment</th><th>Start Date</th><th>Details</th></tr>
<tr><td>Consecutive Estimate Campaign</td><td>Working with meter reading vendors to hire additional meter readers and conduct campaigns to obtain meter reads</td><td>All meters</td><td>ongoing</td><td>
While staffing levels have improved, this industry continues to see challenges with attracting and retaining staff. Continuous review of staffing needs and active hiring wherever necessary.
Longer working hours – evenings/weekend:
Readers will take additional routes, work weekends when weather allows, and additional hours as sunlight hours extend.
Meter reading vendors to offer various incentives for working longer hours, weekends and taking on additional routes.
Knocking on doors:
When a meter reader attends a hard to access property, they will knock on the door and attempt to gain access to read the meter.
Door hangers:
Notices will be left on customer doors when no contact is made asking the customer to contact Enbridge Gas or submit their read.
Attain reads on secondary services:
When attending properties to complete other services, such as battery exchanges, the meter will be read.
</td></tr>
</table>

Initiative	Description	Target Segment	Start Date	Details
Inbound Calls	Call Centre will request a current read from customer on the phone	All meters	ongoing	Call Centre agents will be requesting reads from customers on the phone. Agents will ask the customer to submit a read when calling about the following: ○ Move calls ○ Billing calls where last read is estimated ○ Meter reading inquiries Targeted IVR message for consecutive estimate accounts: • Prompt customer to submit a read
Customer Outreach	Various customer outreach activities to obtain read or make appointment to attend the property	All meters	Ongoing (Annual Spring Launch)	• Targeted emails / text messages and letters to customers encouraging them to submit a meter read online. • Outbound phone calls (dialer/live agent) for 12+ consecutive estimates due to access issues so that Enbrdige Gas can arrange for access moving forward and to attain a read. • Social media - safety and access campaign: ○ reminder about dogs and allowing us access to read meters. ○ Highlight the benefits that regular meter reads provide. • Web messaging to encourage meter reading submissions in combination with social media safety and access campaign starting every Spring.
Operations Engagement	Work with field operations to support hard to access meters	Focus on hard to access meters	Ongoing	• Targeted meter exchange campaign for hard to access meters. • Work with Operations team to attend properties where Enbridge Gas does not have access to the meter. • Operations appointment, attain reads on properties they attend to complete other work.
Process	Review processes for meter reads	All meters	Ongoing	• Continuous review of processes to ensure increased attainment and utilization of meter reads received. • Educate and build trust with customers that reads are used despite the bill showing Estimated. • Prioritize meter reading work to ensure timely billing. • Continuous review of system functionality to allocate meter reads accurately. • Administration team to monitor workload efficiency, targeting work with direct meter reading impact (meter exchange, doubtful meter, crossed meter, etc.) • Continuous review of tolerance thresholds to ensure acceptance of actual meter readings. • Work with Field Operations partners to harmonize process and reduce meter work exceptions. • Increase Back Office staffing levels as needed to support Meter Reading. • Enhance system functionality to ensure timely processing of incoming field work.

Initiative	Description	Target Segment	Start Date	Details
Technology	Roll out new technology to support meter reading	All meters		• Complete roll out of new handheld devices to support real time uploads and increase meter reading time. • Explore reducing billing window to allow for more meter reading days. • Roll out of new meter reading app to support customer initiated reads.

Mitigation Plan – Monitoring Initiatives

Enbridge Gas will monitor the success of each mitigation activity and determine if adjustments need to be made to the initiatives or if new initiatives need to be added. Enbridge Gas will have weekly check points and comprehensive monthly reviews on the progress of mitigation activities. Customer Care will lead the reviews and engage with its Service Partners, Regulatory Affairs, Operations, and Communications.

2024 - 2025 Compliance Objectives

Meter Reading Performance Measurement (7.3.3.1)

This target is difficult to meet at the best of times and has been significantly impacted by increased change in customer behaviour over the past three years (2020 – 2023), as a result of the Covid pandemic, including resourcing constraints and access issues due to change in customer behaviour, weather and safety impacts.

- With the mitigation initiatives taking place in 2024 through to 2025, the yearly performance for 2024 will improve from the 2023 results.
- The annual performance for 2024 is expected to be in the range of 1%, which will include meter reads for circumstances in which Enbridge Gas is not able to access customer meters for various reasons such as, locked gates, inside meters and customers not providing access to the property.
- During the period of this mitigation plan, Enbridge Gas will provide the OEB in Pivotal UX the meter reading results. Enbridge Gas will continue to track the number of inaccessible meters numbers and will report to the OEB upon request.

ENERGY TRANSITION TECHNOLOGY FUND

JANE HUANG, SUPERVISOR COMMERCIAL/INDUSTRIAL TECHNOLOGIES

1. Enbridge Gas has updated this evidence to reflect that the following issue is being addressed in Phase 2 of this Application.

   52) Are the specific proposed parameters for an Energy Transition Technology Fund and associated rate rider appropriate?

2. The purpose of this evidence is to request OEB approval of Enbridge Gas's proposed Energy Transition Technology Fund (ETTF).

3. This evidence is organized as follows:
   1. Rationale
   2. Description of ETTF
   3. Low-Carbon Innovation Funding in Other Jurisdictions
   4. Funding of ETTF
   5. Bill Impacts

1. Rationale

4. Enbridge Gas is proposing to create an ETTF in the amount of $5 million each year over the period of 2025 to 2028. This funding is proposed to be collected through a rate rider rather than through base rates, with a new variance account established to record variances between the amounts collected by the ETTF rate rider and actual costs incurred for ETTF initiatives. Details on the proposed regulatory treatment are provided in Section 4.

5. Enbridge Gas is committed to supporting greenhouse gas (GHG) emissions reduction in Ontario. While the province is on track to achieve its 2030 emissions reduction target of 30% below 2005 levels, the post-2030 target of net-zero will be challenging to meet. Regardless of the energy transition pathway that is chosen, the target is only achievable with significant focus on technology development and investments in innovative technologies, which must be made immediately. As part of the Enbridge Gas Energy Transition Plan safe bets approach provided at EB-2022-0200 Exhibit 1, Tab 10, Schedule 6 and discussed at TC Tr. Vol. 1 to 4 in Phase 1 of this proceeding, Enbridge Gas proposes the ETTF to advance and accelerate research, development, demonstration, and commercialization of low-carbon technologies.

6. Currently, the Research and Innovation Fund (RIF) included in the 2023 to 2025 OEB-approved DSM Plan[1] provides some funding support for technology research, development, and pilots for energy conservation. The RIF is intended to support the objectives and guiding principles of the current DSM Framework and DSM Plan. It is used for funding technical research, maintaining the Technical Resource Manual, funding pilots for collaborative DSM initiatives, research on market barriers for energy efficiency, and technology development activities for energy efficiency technologies and measures for DSM programs. While reduction of GHG emissions may be a by-product of energy efficiency, the primary objective of DSM is helping customers lower natural gas consumption and manage their energy bills and should align with the requirements set out in the DSM Plan approval. DSM funding is currently not applicable to GHG emissions reduction initiatives that do not explicitly reduce natural gas consumption. In contrast to the DSM funding, the ETTF will have a primary focus on technology innovation to drive GHG emissions reduction.

[1] EB-2021-0002.

7. While Enbridge Gas will continue to leverage this DSM funding to develop innovative energy efficiency technologies and programming, important GHG –emissions-reducing elements of energy transition like renewable natural gas (RNG), hydrogen, carbon capture utilization and storage (CCUS) and end-use innovations outside of the current DSM Framework, also require significant technology development in the province, thus requiring meaningful funding levels. For example, RNG costs are currently relatively high, due to high production costs. Technology innovation to maximize supply and lower costs is necessary to make low-carbon fuels accessible and affordable for customers.

8. Enbridge Gas has a long history of leading technology innovation in Ontario. In recent years, by working closely with manufacturers, industry associations, other utilities and government, Enbridge Gas has successfully led technology development projects in a number of areas. For example, Enbridge Gas collaborated with manufacturers and other stakeholders to advance hybrid heating technology. With this work, Enbridge Gas supported the development of the hybrid heating systems including smart controllers to optimize cost, increase efficiency and reduce GHG emissions. This technology has now been fully commercialized and has been installed in 100+ homes in London, Ontario through a pilot program. Building on this success, the Government of Ontario and Enbridge Gas started the Clean Home Heating Initiative, a program funded by the province since 2022 to help up to 1,500 homes convert to hybrid heating with smart control, creating momentum to accelerate its market adoption. This is a clear demonstration of the impact of Enbridge Gas's leadership in technology development.

9. As the main natural gas utility in Ontario serving approximately 3.9 million customers, with deep knowledge of customer needs, expertise in managing energy infrastructure along with strong relationships with stakeholders, Enbridge Gas can

play a central role with the ETTF in accelerating technology innovation and provide customer choices for energy transition.

2. Description of ETTF

10. The ETTF will be used to advance and accelerate research, development, demonstration, and commercialization of low-carbon technologies in line with Canada and Ontario's Energy Transition and GHG emissions reduction goals.

11. Enbridge Gas plans to use the fund to accelerate low-carbon technology development in the following ways:

a) Accelerate technology development and deployment: Enbridge Gas will lead and support Research & Development (R&D) initiatives, field trials and technology demonstration projects to evaluate and improve product performance in Ontario, and to provide training opportunities for contractors to ensure quality installation of equipment;
b) Drive market adoption and transformation: Enbridge Gas will engage with manufacturers, end-use customers, contractors, policy makers and other stakeholders to improve the availability, awareness, accessibility, affordability, and acceptance of low-carbon technologies; and
c) Drive economies of scale by collaborating with other utilities, manufacturers, industry associations and research organizations.

12. The design of the fund takes into consideration the following principles:

a) Predictability - Technology development projects often span over multiple years. It is important that there is reliable funding available to consistently support timely advancement of low-carbon technologies;
b) Flexibility - Flexibility of the fund provides the ability to move budget from one year to the next depending on portfolio mix and opportunities for

partnerships/co-funding. It also allows for adaptation to the prioritization of technologies, sector allocations and timing needs; and

c) Leverage - Projects will leverage funding from government organizations and associations where possible and appropriate.

13. To address the energy transition needs and support customer choices, the ETTF will prioritize technology innovation initiatives that:
    a) Reduce GHG emissions;
    b) Provide safe, reliable and affordable low-carbon options for customers;
    c) Are outside of those needs already funded through DSM;
    d) Are compliant with industry codes and standards;
    e) Range from pre-commercial to commercial activities; and
    f) Cover residential, commercial, and industrial sectors, with appropriate pace of commercialization timeline.

14. The ETTF portfolio will focus on several areas of technology innovation, consistent with the safe bet actions identified in the Energy Transition Plan in EB-2022-0200 Exhibit 1, Tab 10, Schedule 6.

<u>2.1. Supply and Cost of Low-Carbon Fuels</u>

15. Regardless of the pathway to reach net-zero target by 2050, low-carbon fuels such as RNG and low-carbon hydrogen will play an important role in the energy mix. RNG, for example, can use the existing natural gas infrastructure and be blended into natural gas applications to fuel fleets and heat homes and businesses. This offers customers a convenient option to reduce their GHG emissions and avoid carbon charges without having to change appliances or equipment. Currently, the supply of RNG is mainly from biogas generated through anaerobic digestion of farm and food waste and landfill gas. RNG is often priced to

allow project developers to recover their costs and achieve their targeted internal rate of return. ETTF can be used to support further development of alternative technologies such as gasification to enable access to a variety of feedstocks (e.g., agriculture waste, forestry residues, municipal solid waste), thus increasing supply, and over time, lowering cost.

16. For heating, industrial and transportation applications, low-carbon hydrogen could play an important role in reducing the GHG emissions to achieve a sustainable clean energy future. Hydrogen production technologies such as methane pyrolysis offer a unique opportunity to produce hydrogen by using natural gas as a low-cost feedstock and leveraging existing natural gas distribution infrastructure. The ETTF will support the further development of various low-carbon hydrogen production technologies for both central production and distributed on-site production.

2.2. Emission reductions through end-use technology innovation

17. As Enbridge Gas blends more low-carbon fuels into the pipeline in the effort to reduce GHG emissions, new end-use equipment may need to be developed or existing equipment need to be modified and/or upgraded to work safely, effectively and reliably with the changing fuel mix. For example, hydrogen is emerging as an attractive, low-carbon alternative fuel for a variety of end-use applications. As Enbridge Gas increases the hydrogen blending percentage into the existing natural gas pipeline, potential technical challenges with end-use equipment must be addressed. The ETTF will support innovation initiatives to develop end-use equipment working with a low-carbon fuel mix. In addition, ETTF will include end-use technologies integrated with renewable power generation, and end-use energy efficiency technologies not covered by DSM funding.

2.3. CCUS

18. Enbridge Gas intends to use ETTF to research, test and pilot promising CCUS technologies for commercial and industrial applications. There are numerous areas within the CCUS supply chain where research and development activities will advance its adoption.

19. The majority of commercial carbon capture systems have currently been limited to large scale applications such as natural gas processing or chemical manufacturing facilities.[2] For other industrial and commercial facilities, the application of CCUS is relatively new, requiring further research, development and demonstration. Several methods (e.g., pre-combustion or post-combustion) and types (e.g., chemical/physical absorption, membrane separation, cryogenic, or chemical looping) are at varying stages of commercialization. The ETTF will support the research, development, demonstration, and commercialization of CCUS technologies for industrial and large commercial applications in Ontario.

20. The utilization of captured carbon dioxide to create higher value products is another important area of research that could maximize carbon removal from atmosphere and minimize transportation and sequestration requirements, particularly where emission sources are not situated in reasonable proximity to storage reservoirs. The ETTF will support the development of carbon dioxide-derived products for emissions reduction to increase flexibility in carbon management and removal.

21. Overall, CCUS provides significant opportunity for GHG emissions reduction and development. To ensure solutions developed could be used by a wide variety of

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[2] Global CCS Institute (2023). Global Status of CCS 2023, https://status23.globalccsinstitute.com/, p.13.

customers, Enbridge Gas's focus will be on technologies that are modular, scalable and serve various applications based on their specific GHG emissions qualities.

22. In addition to the three areas described above, the ETTF may support further areas which enable GHG emissions reduction when new technologies and opportunities emerge.

3. Low-Carbon Innovation Funding in Other Jurisdictions

23. Support for and existence of utility-led customer funded innovation funds managed by utilities are available in a number of jurisdictions. A 2018 report[3] prepared by Concentric Energy Advisors, identified programs in jurisdictions across the globe where regulators have determined that they "meet specific innovation or demonstration project requirements to merit customer funding". The Clean Growth Innovation Fund in British Columbia[4] and SoCalGas Research Development and Demonstration Program[5] are examples of clean energy innovation funds managed by a natural gas utility.

24. In 2020, British Columbia Utilities Commission (BCUC) granted approval to FortisBC Energy Inc. (FEI) to manage the Clean Growth Innovation Fund for $24.5 million to "accelerate the pace of clean energy innovation, to achieve performance breakthroughs and cost reductions, and to provide cost effective, safe and reliable

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[3] Concentric Energy Advisors. (2018 April). Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation, https://ceadvisors.com/wp-content/uploads/2018/05/Concentric-Final-Innovation-Report-4.23.18.pdf
[4] Fortis BC. Clean Growth Innovation Fund. https://www.fortisbc.com/about-us/climate-leadership/clean-growth-innovation-fund#:~:text=We%27ve%20made%20a%20commitment,like%20Renewable%20Natural%20Gas%20initiatives
[5] SoCalGas. Research, Development and Demonstration. https://www.socalgas.com/sustainability/research-development-demonstration-rdd

solutions”[6] for their customers from 2020 to 2024. The BCUC found that there is clearly a need for innovation to help meet the aggressive targets for GHG emissions in BC, and that the “basic charge fixed rate rider of $0.40/month is just, reasonable and not unduly discriminatory”.[7] This fund is incremental to FEI’s DSM programming funds.

25. In California, SoCalGas has been managing a ratepayer funded natural gas research, development, and demonstration program (RD&D) for many years, “working towards the goal of achieving net zero GHG emissions in our operations and delivery of energy by 2045”[8]. The RD&D program at SoCalGas supports projects in five main research domains: “(a) Customer End-Use Applications which develop and commercialize technologies that improve efficiency, reduce environmental impacts of natural gas end-use applications, and support development and deployment of technologies that meet emissions and efficiency goals; (b) Clean Generation which focuses on supporting the development of high-efficiency and low-emission distributed generation systems; (c) Clean Transportation which supports transportation infrastructure; (d) Gas Operations which develop technologies for public and employee safety, operational efficiencies, system reliability, and reduced environmental impacts; and (e) Low-Carbon Resources which focus on technologies to improve biomethane production and use”.[9] The program spending in 2022 was $15 million US, of which over $8.5 million was spent in the areas of End-use Application, Clean Generation, and Low

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[6] British Columbia Utilities Commission. (2020 June 22). Decision and Orders G-165-20 and G-166-20. https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/481438/1/document.do. p.145.
[7] Ibid, p.156.
[8] SoCalGas. Research, Development, and Demonstration (RD&D). https://www.socalgas.com/sustainability/research-development-demonstration-rdd
[9] Public Utilities Commission of the State of California. (2019 September 26). Decision Addressing the Test Year 2019 General Rate Cases of San Diego Gas & Electric Company and Southern California Gas Company, Decision 19-09-051. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M316/K704/316704666.PDF p. 374.

-Carbon Resources.[10] Subsequently, SoCalGas received approval of $16.9 million for its 2023 RD&D program plan.[11]

4. Funding of ETTF

26. Enbridge Gas is proposing to fund the ETTF through a rate rider rather than through base rates. This proposed regulatory treatment will provide transparency and certainty, as the amounts collected will be earmarked for the stated purpose of the ETTF and nothing else. Enbridge Gas will provide a dedicated, continuous, reliable funding stream for technology research and innovation.

27. The rate rider will be a fixed monthly customer charge to be collected from in-franchise customers so that each customer contributes equally to the development of low-carbon energy technologies. The forecast amount to be collected from customers is $5 million per year over the 2025 to 2028 period. There are no costs associated with the ETTF in the budget underpinning the 2024 Forecast Revenue Requirement approved in Phase 1, and the ETTF is incremental to the 2024 Revenue Deficiency. Please see Phase 2 Exhibit 8, Tab 1, Schedule 2 for the rate design and recovery proposal of the ETTF.

28. Enbridge Gas proposes a new variance account to capture the variance between the actual amounts collected by the ETTF rate rider and actual costs incurred for ETTF initiatives. The request for the proposed variance account is provided at Phase 2 Exhibit 9, Tab 1, Schedule 3. Enbridge Gas intends to align its spending with the amount collected in the proposed rate rider and proposes to report on the balance in the Deferral and Variance Account each year. Enbridge Gas proposes

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[10] SoCalGas. (2023). 2022 Annual Report Research, Development, and Demonstration. https://www.socalgas.com/sites/default/files/2022_SoCalGas_RDD_Annual_Report.pdf
[11] Public Utilities Commission of the State of California (2023 November 30). Resolution G-3601. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K196/521196139.pdf

to review the future evolution of the ETTF and the balance in the ETTF variance account in its next rebasing application.

5. Bill Impacts

29. The monthly bill impact of the ETTF is $0.11 per customer. The annual collection is forecasted at $5 million. The majority of customers support contributing towards an innovation and technology fund with the goal of advancing low-carbon technologies as shown in the customer engagement in EB-2022-0200 Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 17.

UNREGULATED STORAGE COST ALLOCATIONS AND ELIMINATIONS

JASON VINAGRE, MANAGER REGULATORY ACCOUNTING
RYAN SMALL, TECHNICAL MANAGER REGULATORY ACCOUNTING
MELINDA YAN, MANAGER O&M
MICHELLE TIAN, MANAGER CAPITAL FINANCIAL PLANNING & ANALYSIS
RACHEL GOODREAU, MANAGER REVENUE AND COST OF GAS

1. Enbridge Gas has updated this evidence to reflect that the following issue is being addressed in Phase 2 of this Application:

    50) Is the allocation of capital assets and costs between utility and non-utility (unregulated) storage operations appropriate?

2. This evidence presents the proposed harmonized unregulated storage cost allocation methodology for Enbridge Gas as directed by the OEB[1]. The purpose of this evidence is to summarize the storage cost allocation methodologies previously in place at EGD and Union and to describe and request approval for the proposed harmonized unregulated storage cost allocation methodology. Ernst & Young LLP (EY) was retained by Enbridge Gas to assist management in its determination of the Company's harmonized unregulated storage cost allocation methodology.

3. Enbridge Gas has updated the evidence to reflect the impacts of the Phase 1 Rate Order, as well as updates to the allocators to reflect the most recent available actuals for 2022.

[1] EB-2020-0256, Decision and Order, April 22, 2021, p.4.

4. This evidence is organized as follows:
    1. Background and History
    2. Proposed Harmonized Methodology
    3. Impact of the Proposed Harmonized Methodology

1. Background and History

5. Prior to amalgamation, EGD and Union both sold storage services to in-franchise and ex-franchise customers. In-franchise customers could purchase cost-based storage services and all customers could purchase market-based storage services. Since the amalgamation, the combined storage facility continues to offer the same suite of storage services to meet customers' storage demands.

6. In 2006, as part of its Natural Gas Electricity Interface Review (NGEIR)[2] the OEB determined that EGD and Union operated in competitive storage markets. Consequently, the OEB determined that it would forebear from regulating either Utility's storage services offered to ex-franchise customers, for new storage services offered to in-franchise customers, and for all storage services offered by other storage operators.

7. As a result of the OEB's NGEIR Decision[3], storage services at EGD and Union were separated into regulated and unregulated storage operations. Separate and independent reviews were carried out by each company to determine the appropriate cost allocation process for its regulated and unregulated storage operations. Union's methodology, which assigned storage-related expenses on an asset basis, was approved in 2011[4]. EGD's methodology, which relied on storage

[2] EB-2005-0551.
[3] Ibid, OEB Decision with Reasons, November 7, 2006.
[4] EB-2011-0038, OEB Decision and Order, January 20, 2012.

activity, was approved in 2012[5]. These methodologies continued to be in place until the end of 2023.

8. Following amalgamation, EY was retained to assist Enbridge Gas in developing and documenting an integrated cost allocation methodology that best represented the separation of activity and costs between regulated and unregulated storage operations. Enbridge Gas is proposing to implement the changes set out in the resulting Unregulated Storage Cost Allocation Report provided at Attachment 1 and harmonize the unregulated storage allocation methodology effective January 1, 2024.

2. Proposed Harmonized Methodology

9. The harmonized methodology was guided by the NGEIR Decision[6], and subsequent OEB decisions on EGD's and Union's unregulated storage allocation methodologies referenced in paragraph 7. The following guiding principles were applied to ensure the methodology selected was appropriate and adhered to established regulatory principles. These are:
    a) Fair allocation of costs based on the underlying activities;
    b) Consistency of assumptions, decisions, and approach;
    c) Transparency and traceability throughout the allocation process;
    d) Consistency with prior OEB findings and decisions;
    e) Conformity with operational or organizational changes due to amalgamation;
    f) Ease of implementation to support regular updates; and
    g) Adaptability to current or future IT systems.

[5] EB-2011-0354, Decision on Revised Settlement Agreement, November 2, 2012.
[6] EB-2005-0551, OEB Decision with Reasons, November 7, 2006.

10. The proposed harmonized methodology is largely consistent with the previously approved Union storage allocation methodology, which has historically received more input through prior OEB proceedings due to the relative size and scope of Union's storage operations compared to EGD's. Modifications to the Union methodology are in line with the guiding principles Enbridge Gas seeks to achieve. Allocated costs will be based on the underlying amalgamated unregulated storage operations. A consistent set of assumptions and approach will be applied to harmonized cost groupings within the amalgamated storage operations structure. Calculations are transparent and traceable and support regular updates as part of the annual budget process.

11. The following section provides an overview of the proposed harmonized approach. Supporting rationale is detailed in the Unregulated Storage Cost Allocation Report provided at Attachment 1. Table 1 summarizes asset and expense elements in scope, along with the harmonized allocation approach, including applicable page references within the Unregulated Storage Cost Allocation Report. In addition, the calculation for each element under the harmonized allocation methodology, underpinning the 2024 Test Year Budget, is summarized in Attachment 2. For each element, the harmonized methodology is either 1) consistent with the Union approach, or 2) a modification of the Union approach. Where no change is indicated, the prior EGD and Union OEB-approved methodologies were the same and no further alignment is required. In addition to meeting guiding principles, Enbridge Gas believes that the proposed changes are appropriate as they best represent the costs incurred by the unregulated storage business and remain consistent with historical OEB decisions.

Table 1
Summary of Methodology Changes

Allocation Area	EGI Harmonized Allocation Methodology	Unregulated Storage Allocation Report Page Reference
Assets		
2.1 Materials and Supplies	Modified Union methodology	Not addressed in report
2.2 New Storage assets (net)	No change – EGD and Union methodologies aligned	9-11
2.3 General plant assets (net)	Modified Union methodology	11-14
Expenses		
2.4 Cost of gas: Unaccounted for gas	Modified Union methodology	14-17
2.5 Cost of gas: Fuel used to move gas	Union methodology	16-17
2.6 Operating & Maintenance: Storage operations	Modified Union methodology	17-20
2.7 Operating & Maintenance: Storage support – administrative and general	Modified Union methodology	20-21
2.8 Operating & Maintenance: Storage support – variable	Union methodology	21-22
2.9 Depreciation expense: Storage Assets	No change – EGD and Union methodologies aligned	22-24
2.10 Depreciation expense: General Plant Assets	Union methodology	22-24
2.11 Property tax expense: Storage Assets	Union methodology	24-25
2.12 Property tax expenses: General Plant Assets	Union methodology	24-25
2.13 Unutilized in-franchise space	No change – allocation area only applicable to Union	25-27
2.14 Interest expense on long-term debt	Union methodology	26-27

2.1. Materials and Supplies

12. Prior to 2019, Union allocated materials and supplies inventory to unregulated storage in proportion to unregulated storage plant as a percentage of total plant. Throughout the 2019 to 2023 deferred rebasing term, Enbridge Gas continued to

apply a portion of materials and supplies inventory to its unregulated business leaving only the utility portion in its working capital component for the Union rate zones. Prior to 2019, EGD did not allocate any of its materials and supplies inventory to unregulated storage operations, which continued through the deferred rebasing term for the EGD rate zone.

13. To harmonize, Enbridge Gas will allocate a portion of its average of monthly averages of materials and supplies working capital inventory balance to unregulated storage operations using a composite allocation rate based on the equally weighted proportion of the Company's unregulated storage assets and unregulated storage O&M expenses relative to total assets and O&M expenses. This proposed methodology is in line with the allocation of general plant assets as noted below in Section 2.3, and is an appropriate allocation based on cost causality as the consumption of materials and supplies will result in a mix of costs recognized as O&M and capital costs. The portion allocated to unregulated storage operations will be excluded from Enbridge Gas's utility working capital.

2.2. New Storage Assets

14. Pursuant to the NGEIR Decision[7], EGD's storage assets were allocated 100% to the regulated business as the existing assets were required to serve in-franchise customers. Union's storage assets were split between the regulated and unregulated business based on a one-time allocation. All new storage assets constructed subsequent to the NGEIR Decision are classified into one of three categories for the purpose of determining allocations to regulated and unregulated operations. The categories are as follows:

[7] EB-2005-0551, OEB Decision with Reasons, November 7, 2006.

Category 1 - New storage assets resulting in additional space and withdrawal capability – allocated to unregulated storage.

Category 2 - New storage assets to maintain existing assets or replace existing end-of-life assets – allocated to regulated or unregulated storage, consistent with the allocation of the original asset.

Category 3 - New storage assets to replace and enhance existing assets – allocated to regulated and/or unregulated storage based on the underlying project driver.

Please see page 10 of the Unregulated Storage Cost Allocation Report provided at Attachment 1 for additional detail regarding the cost allocation approach under each category.

15. Allocations of new storage assets between the regulated and unregulated storage business are made on a one-time basis for each new storage asset placed in-service. This enables maintenance of plant accounting records at the individual asset level for regulated and unregulated storage operations. In addition, the split between unregulated storage assets and regulated utility storage assets at each individual storage pool is updated annually to reflect additions and retirements that occurred throughout the prior year, for the purposes of allocating costs associated with capital maintenance of the assets.

16. No change is required for harmonization as the EGD and Union OEB-approved methodologies align.

2.3. General Plant Assets

17. The harmonized allocation of general plant assets first requires an aligned definition of general plant assets to include certain EGD buildings and land assets to ensure consistency in its application upon implementation.[8] These assets were historically classified as distribution plant assets and were not allocated to EGD's unregulated storage operations. Union historically allocated all general plant assets by applying different allocators for vehicles and heavy work equipment, and all other general plant assets.

18. Under the harmonized methodology, new Enbridge Gas general plant assets are allocated monthly to the unregulated storage operations using a composite allocation rate based on the equally weighted proportion of the Company's unregulated storage assets and unregulated storage O&M expenses relative to total assets and O&M expenses. To implement the harmonized methodology, a one-time allocation of EGD rate zone general plant assets was required and undertaken, as of December 31, 2023, using this approach. Please see Phase 2 Exhibit 1, Tab 13, Schedule 2, Attachment 2, page 3.

19. The modification of the Union methodology will simplify and improve the traceability of the allocator.

2.4. Cost of Gas: Unaccounted for Gas

20. Enbridge Gas will allocate unaccounted for gas, which includes all components of gas loss, such as leakages, venting, meter errors and other similar considerations to unregulated storage monthly using actual gross unregulated storage activity for a

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[8] See *Classification of Buildings and Structures* in EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, p.13 for more details on the harmonization of general plant assets specific to buildings/structures.

given month as a percentage of total actual gross storage and transportation activity for a given month. Gross activity is the sum of the absolute volumes as it relates to both injections and withdrawals.

21. The change to allocating based on monthly volumetric activity is a modification of Union's annual allocation of unaccounted for gas to capture activity fluctuations as well as gas reference price fluctuations throughout the year.

2.5. Cost of Gas: Fuel Used to Move Gas

22. Enbridge Gas will allocate compressor fuel to the unregulated storage business using actual net daily unregulated storage activity as a percentage of total actual net daily storage and transportation activity. Net activity is composed of injections less withdrawals.

23. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology for this allocation area.

2.6. Operating & Maintenance Expenses Background

24. Operating and maintenance (O&M) costs represent the expenses required to operate and maintain all Enbridge Gas natural gas distribution, storage, and transmission activities. A portion of O&M expense is recognized as supporting unregulated storage functions. The categories of O&M costs allocated to the unregulated storage are the following:
    a) O&M: Storage Operations
    b) O&M: Storage Support – Administrative & General
    c) O&M: Variable Storage Support Costs

2.7. O&M: Storage Operations

25. Enbridge Gas will allocate storage operations O&M costs, captured in asset category specific cost pools, based on the underlying proportion of storage asset category assets, assigned to the unregulated storage operations. These storage asset category proportions will be updated annually. The harmonized approach is simplified in comparison to the more complex, multi-factor (i.e., asset category and asset location) approach previously used by Union.

26. This is a modification of the Union methodology where all storage locations of the same asset class will use a single average storage asset allocator. In the previous Union methodology, each storage location had a different allocator within the same asset class. The harmonized methodology will be used to simplify and increase the transparency of the calculation while maintaining a causal linkage.

2.8. O&M: Storage Support - Administrative and General

27. Enbridge Gas will allocate a portion of actual administrative and general (A&G) O&M support costs (excluding the variable O&M storage support costs provided in Section 2.8) using an allocation rate based on the proportion of prior years unregulated storage O&M expenses relative to total net O&M expenses, both exclusive of A&G costs for the determination of the allocator.

28. This is a modification of the Union methodology which serves to enhance the accuracy of the allocations by removing the influence of storage support costs as part of the calculation for the storage support allocator.

2.9. O&M: Storage Support – Variable

29. Enbridge Gas will allocate, by department, variable storage support O&M costs based on expected time spent on unregulated storage support activities carried out by these departments. Support costs vary from year-to-year depending on the nature and level of unregulated storage activity being carried out by departments or functions such as Business Development, Asset Management, Lands and Permitting, Engineering and Regulatory Affairs.

30. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology.

2.10. Depreciation Expense: Storage Assets

31. The OEB approved harmonized utility depreciation methodologies and rates effective January 1, 2024, as set out in the Phase 1 Decision[9]. Depreciation expense is calculated at the individual asset account level using the applicable utility rates for the storage class as the unregulated assets are an allocation of regulated assets and therefore have the same expected useful lives.

32. No change is required for harmonization as the Union and EGD OEB-approved methodologies are aligned.

2.11. Depreciation Expense: General Plant Assets

33. The depreciation expense related to the general plant assets is allocated to unregulated storage according to the proportion of unregulated general plant assets to total general plant assets.

[9] EB-2022-0200, Decision and Order, December 21, 2023, pp.82-92.

34. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology.

2.12. Property Tax expense: Storage Assets

35. Actual property taxes related to storage assets will be allocated to unregulated storage operations based on the proportion of unregulated storage assets (excluding general plant assets) to total storage assets.

36. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology.

2.13. Property Tax expense: General Plant Assets

37. Property tax related to general plant assets will be allocated to the unregulated storage operations using the same allocator used to allocate new general plant assets provided in Section 2.3.

38. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology.

2.14. Cost of Unutilized In-franchise Storage Space

39. Unutilized in-franchise (regulated) storage space is the difference between the amount of storage space reserved for in-franchise customers and the amount required by in-franchise customers. The portion of storage space that is not being used by in-franchise customers is made available to ex-franchise customers for short-term storage contracts.

40. There was 11.3 PJ of unutilized in-franchise storage space in the Union rate zones at the time of Union's 2013 Cost of Service[10] and no unutilized in-franchise storage space in the EGD rate zone. The OEB approved a cross charge of $3.81 million for the costs associated with the 11.3 PJ of unutilized in-franchise storage.[11] This cross charge is adjusted annually in proportion to the actual amount of unutilized in-franchise storage space relative to the 11.3 PJ OEB-approved amount through the Short-Term Storage Deferral Account. Costs recorded through this cross charge do not impact the costs allocated to unregulated storage operations.

41. For the 2024 Test Year Forecast, Enbridge Gas proposes that the excess utility storage space that previously existed in the Union rate zones will be used to serve all Enbridge Gas in-franchise customers, as described at Phase 2 Exhibit 4, Tab 2, Schedule 1, page 6.

42. As per the Phase 1 Settlement Agreement[12], matters related to gas storage are being determined in Phase 2 and parties agreed that until a determination is made in Phase 2, Enbridge Gas will maintain its current levels of market-based storage. Therefore, Enbridge Gas expects that there will continue to be excess utility storage space in the Union rate zones until at least the implementation of outcomes of the OEB's Phase 2 decision. During this interim period, Enbridge Gas will continue to track the excess utility space non-utility cross charge using the existing methodology and record any net ratepayer benefit from the sale of excess utility storage space in the Short-Term Storage Deferral Account.

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[10] EB-2011-0210, Decision and Order, October 24, 2012.
[11] Ibid.
[12] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p. 35.

2.15. Interest Expense on Long-term Debt

43. The cost of long-term debt is allocated between regulated and unregulated operations in proportion to regulated and unregulated rate base as a percentage of total rate base.

44. This approach is consistent with Union's OEB-approved methodology and was adopted for the EGD rate zone in 2019.

3. Impact of the Proposed Harmonized Methodology

45. Table 2 summarizes the forecasted impact of implementing the harmonized unregulated storage allocation methodology for the 2024 Test Year relative to the previously approved methodologies. Enbridge Gas has updated Table 2 to reflect the impacts of revisions due to the Phase 1 Rate Order, as well as updates to the allocators noted above to reflect the most recent available actuals for 2022. Attachment 2 summarizes the details of the 2024 Unregulated Storage Cost allocation calculation based on the harmonized methodology.

Table 2
Increase/(Decrease) in Unregulated Storage Cost Allocation Resulting from Harmonized Methodology

Line No.	Particulars ($ millions)	2024 Harmonized Methodology	2024 Current Methodology	2024 Impact
		(a)	(b)	(c) = (a) - (b)
	Unregulated Storage Asset Balances			
1	Materials and Supplies Inventory	2.1	2.7	(0.6)
2	Net Underground Storage Plant	436.8	436.8	-
3	Net General Plant	10.4	6.1	4.3
4	Total	449.3	445.6	3.7
	Unregulated Storage Operating Expenses			
5	Cost of Gas: Unaccounted For Gas	5.3	5.3	0.0
6	Cost of Gas: Fuel Used to Move Gas	2.9	2.9	0.0
7	O&M: Storage Operations	7.6	4.6	3.0
8	O&M: Storage Support – Administrative and General	7.4	4.4	3.0
9	O&M: Storage Support – Variable	1.3	0.6	0.7
10	Depreciation Expense: Storage Assets	18.0	18.0	-
11	Depreciation Expense: General Plant Assets	1.3	0.8	0.5
12	Property Tax Expense: Storage Assets	1.9	1.7	0.2
13	Property Tax Expense: General Plant Assets	0.0	0.0	0.0
14	Unutilized In-franchise Space	-	-	-
15	Interest Expense on Long Term Debt	12.3	12.3	-
16	Total	58.0	50.6	7.4

46. The overall annual impact is a net increase to unregulated storage assets and expenses, and therefore, a net decrease to regulated storage assets and costs. The net decrease to regulated storage costs is primarily driven by a higher allocation of O&M and depreciation expense to unregulated storage operations.

47. The increase in O&M costs allocated to unregulated storage is attributable to the impact of adopting the Union methodology, or a modified version of it, on EGD rate

zone costs. Storage operations O&M will be allocated to unregulated storage using an asset-based allocation. Additionally, support costs were previously based on a markup of direct labour for storage. Instead, the harmonized methodology applies an allocation for unregulated storage based on a more comprehensive pool of administrative and general costs that is based on the proportion of unregulated storage O&M to total O&M, as well as activity-based allocations for variable support costs.

48. The increase in net general plant assets and resultant depreciation expense allocated to unregulated storage is attributable to adopting the Union methodology, or a modified version of it, on EGD rate zone assets. General plant assets will now be allocated to unregulated storage using an allocator derived from asset information and O&M expenses. The approach supports the nature of general plant assets as their function is to support the day-to-day operations of Enbridge Gas, which includes storage operations.

Enbridge Gas Inc: Unregulated Storage Cost Allocation

21 June 2020

Building a better working world

Table of Contents

I. Executive Summary

EY was retained by Enbridge Gas Inc. (Company or EGI) to assist management in defining the Company's harmonized unregulated storage cost allocation methodology, subsequent to a January 2019 amalgamation of Enbridge Gas Distribution (Enbridge Gas or EGD) and Union Gas Limited (Union Gas or UG).

EY obtained an understanding of the current practices and methodology at the legacy entities EGD and UG through review of third-party cost allocation reports and discussions with EGI personnel. This included developing an understanding of the nature of costs incurred, the causation of these costs as they relate to unregulated storage operations, and the criteria by which the cost allocations are determined. As part of EY's assistance to management in developing a single integrated cost allocation methodology between regulated and unregulated storage operations, EY documented management's rationale in determining the cost drivers, basis for allocations, and causality to unregulated storage activities.

EY observed that the updated methodology for EGI incorporates cost allocations which management has determined to best represent unregulated activity for storage operations. Based on our understanding of the current practices, prior cost allocation reports and applicable regulatory precedents established by the Ontario Energy Board (Board or OEB), the harmonized methodology for EGI unregulated storage cost allocation proposed by management attempts to fairly and reasonably reflect costs incurred by the unregulated and regulated business and based on our observations, is consistent with applicable regulatory precedents established by the OEB in relation to the respective historical filings of EGD and UG.

II. Purpose and Scope

As of January 1, 2019, Enbridge Gas Inc. amalgamated Union Gas and Enbridge Gas to form EGI. At the time of amalgamation, both legacy entities had unregulated storage operations, which per the OEB's Natural Gas Electricity Interface Review ("NGEIR") in EB-2005-0551, meant that these storage services operated in a competitive market and would not be subject to rate regulation. The two legacy entities were required to identify and separate costs between the regulated and unregulated storage operations for the purposes of setting regulated utility rates and for calculating earning sharing. The two legacy entities each developed and utilized their own methodology, which was previously and separately approved by the OEB.

As a result of the amalgamation, EGI requires a harmonized cost allocation methodology for unregulated storage operations. The purpose of this report is to summarize the current unregulated storage cost allocation methodology being utilized at the legacy entities, and document the harmonized allocation methodology for the amalgamated entity going forward. As part of our engagement, EY obtained an understanding of the current approved methodology at the two legacy entities and assisted management in determining a harmonized and streamlined policy for the amalgamated entity that meets the OEB regulatory requirement of ensuring that costs are allocated fairly based on the underlying business operations. EY did not confirm adherence and compliance to the approved methodology. EY has assisted management in determining the implementation requirements of the harmonized policy for the amalgamated entity, however, the implementation of the new policy is anticipated for January 1, 2021 (or at a future date to be determined by management) and will be undertaken by management without EY assistance. The expected impacts detailed in this report are limited to the structure and operational decisions of the organization as at the issuance of this report.

The scope of this report is limited to cost allocations for unregulated storage operations and does not include other unregulated businesses and the costs associated with those areas respectively. This report has been prepared for Enbridge Gas Inc.

III. Background

Natural gas storage

Natural gas can be stored for an indefinite period in natural gas storage facilities for later consumption. EGI offers storage services to wholesale market participants and power generation customers. The legacy entities (EGD and UG) have operated large underground gas storage facilities in southwestern Ontario, and with the amalgamation, EGI's underground storage assets have become one of the largest facilities in North America. Other characteristics of the storage services provided include[1]:

- Services are offered on a firm basis and range from high deliverability storage (10- or 20-day service) to seasonal storage;
- Customers pay a monthly demand charge, as well as variable charges including commodity and fuel;
- Contract terms range from 1 to 10 years; and
- Customers have the option to cycle volumes within their contractual parameters and pay variable charges on the cycled volumes.

NGEIR decision

In 2006, the OEB determined that the Ontario storage operators (EGD and UG) compete in a competitive market because the geographic market includes part of the US in which neither EGD nor UG has market power. The OEB concluded that the Ontario storage operators will not be required to share the profits on long-term storage transactions that use storage space not needed to serve in-franchise needs because that capacity now constitutes a "non-utility" asset for which the shareholders appropriately bear the risk. [2]

Impact of NGEIR decision on EGD and UG

The impact of the decision was that storage services at each legacy entity had to be separated into regulated and unregulated operations. While regulated storage must operate within the parameters of OEB guidelines, unregulated storage is not monitored by the Board. Unregulated storage provides wholesale market participants and power generation customers with capacity to store gas product in facilities stationed across Canada. The storage services that fall within the unregulated service parameter for EGD and UG include storage services for customers outside the franchise areas, new storage services for in-franchise customers, and all other storage services offered by other storage operators (including operators affiliated with the two entities).

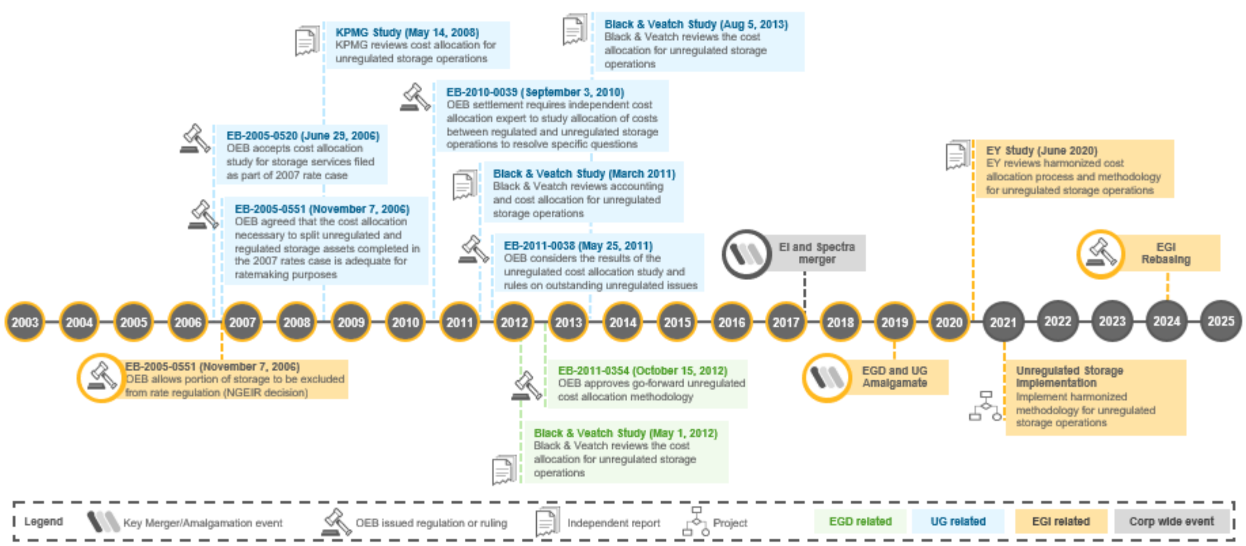
At the time of the NGEIR decision, EGD's existing storage investment was required to serve its in-franchise customers, while UG had storage operations that served ex-franchise customers. As a result, UG carried out a cost allocation study[3] to determine a one-time separation and transfer of its storage assets existing at the time of the NGEIR decision to their unregulated operations. This was not required

[1] Enbridge, https://www.enbridgegas.com/Commercial-and-Industrial/Data-Sources/Gas-Storage (Accessed May 11, 2020)
[2] EB-2005-0551 – NGEIR Decision with Reasons dated November 7, 2006, page 4
[3] KPMG Report for Union Gas – Unregulated Operations Accounting and Reporting Documentation (May 14, 2008)

for EGD because EGD did not have excess storage capacity at the time to service ex-franchise customers. Instead, EGD utilized an incremental costing approach for identification of new storage assets to either its regulated or unregulated operations. In the early 2010s, the legacy entities, EGD and UG, each had independent reviews of the cost allocation process for regulated and unregulated underground storage operations[4,5,6].

Since the NGEIR decision, both entities were required to identify capital investments related to their unregulated operations, maintain separate plant records, and separate expenses between regulated and unregulated operations. The two legacy entities chose different methodologies that were each separately approved by the OEB[7,8] using the third-party cost allocation reports as independent evidence. Specifically, the legacy UG methodology for assigning storage-related expenses was largely based on an asset basis whereas it was based on storage activity at legacy EGD. Given the magnitude of legacy UG's unregulated operations compared to that of legacy EGD, the cost allocation methodology at legacy UG has received greater guidance and input from the Board. For the year ended 2019, unregulated operating expenses at UG were $28.6M, compared to $5.7M at EGD.

Unregulated storage cost allocation timeline



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[4] EB-2011-0354, Exhibit D2, Tab 5, Schedule 1 – Black & Veatch Independent Review
[5] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[6] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[7] EB-2011-0038 – Decision and Order (January 20, 2012) and EB-2013-0365 – Settlement Agreement (June 3, 2014)
[8] EB-2011-0354 – Decision on Settlement Agreement (October 15, 2012), EB-2015-0114 – Decision and Interim Rate Order (December 10, 2015)

IV. Methodology Design Principles

Although each legacy methodology remains appropriate, the amalgamation has created the need for a single harmonized cost allocation methodology for unregulated storage operations. The following key principles were used in developing EGI's harmonized cost allocation process for its unregulated and regulated storage operations:

- The harmonized methodology is a fair allocation of costs that accurately represents the underlying activities of the unregulated and regulated operations
- There is a consistency of assumptions, decisions and approach taken in each component of the methodology to determine regulated and unregulated costs
- The cost allocation process allows for transparency and traceability, such that the rationale for the structure, methodology, and computational results can be understood, evaluated internally and externally by independent third parties, and updated as required
- The allocation methodology continues to address prior OEB findings and is consistent with decisions made by the Board with respect to allocation methodology for storage operations
- The methodology appropriately addresses any operational or organizational changes as a result of the amalgamation
- The allocation methodology is feasible and practical in cost and effort to implement
- The approach taken for each component of the methodology can be customized and adapted to current and expected future IT systems

V. EGI Cost Allocation Methodology for Unregulated Storage Operations

This section details the current state cost allocation methodology used at legacy EGD and UG that was reviewed in prior unregulated storage cost allocation studies and approved by the OEB, as well as the harmonized EGI cost allocation methodology to be implemented in 2021 (or at a future date to be determined by management), including expected impact.

Overall structure

Based on the previous independent studies[9,10,11,12], inspection of the unregulated trial balance at legacy EGD, and inspection of the unregulated allocator model at legacy UG, the following cost elements related to underground storage operations were identified:

Asset allocation

A. New storage assets
B. New general plant assets

Expense allocation

C. Cost of gas: Fuel used to move gas and lost and unaccounted for gas
D. Operating & maintenance expenses
    i. O&M: Storage operations
    ii. O&M: Storage support costs related to administrative and general activities, and corporate administrative and general overheads
    iii. O&M: Variable storage support costs
E. Depreciation expense
F. Property tax
G. Cost of unutilized in-franchise storage capacity
H. Interest expense on long-term debt

A portion of each of these cost elements are allocated to the unregulated storage operations either on a one-time basis, monthly or an annual basis with allocators that are updated periodically. Each of these elements are discussed in further detail below. Please refer to *Appendix A* for a summary of the 2019 unregulated actual asset and expense cost elements, and the timing of the cost allocations to the unregulated storage operations.

A. New Storage Assets

New storage assets are assets constructed after the NGEIR decision for use in storage operations and currently, they include the following asset classes: structures and improvements, storage wells, field

[9] KPMG Report for Union Gas – Unregulated Operations Accounting and Reporting Documentation (May 14, 2008)
[10] EB-2011-0354, Exhibit D2, Tab 5, Schedule 1 – Black & Veatch Independent Review
[11] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[12] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review

lines, compressor equipment, measuring and regulating equipment and dehydration. Storage assets also include base pressure gas, which represents gas held within the gas storage system to provide the base, or minimum pressure needed to meet operational requirements with the underground assets currently in place.

Legacy EGD and UG unregulated storage cost allocation methodology summary

Storage assets are directly attributable to either the regulated or unregulated storage operations. Allocations of new storage assets to the unregulated storage business are made on a one-time basis for each new storage asset added and enable the legacy entities to maintain plant accounting records at the individual asset level for its unregulated storage operations. In addition, the split between unregulated storage assets and the regulated utility assets at each individual storage pool is updated annually to reflect additions and retirements that occurred throughout the prior year, for the purposes of allocating costs associated with capital maintenance of the assets at both legacy EGD and legacy UG. At legacy UG, the split between unregulated storage assets and the regulated utility assets is applied to allocate O&M expenses between the regulated and unregulated storage operations.

New storage assets constructed can be classified into three categories for the purpose of allocation to the unregulated storage operations:

1) New storage asset resulting in additional capacity and deliverability

   These projects consist of storage-related assets that are installed to increase storage capacity or deliverability, ultimately providing growth opportunities for the unregulated storage business. As the storage requirements of the in-franchise customers at legacy EGD and UG are satisfied by existing storage assets and third-party storage (in the case of legacy EGD), these projects are driven by the operational needs of the unregulated storage business. Therefore, the capital project costs of these new storage assets are directly allocated to the unregulated storage operations at the two legacy entities.

2) New storage asset to maintain existing assets or replace existing end-of-life asset

   These projects consist of storage-related assets that only replace existing storage assets without providing any operational efficiencies or growth opportunities. This includes costs incurred to replace the asset, recondition the asset, or enable the asset to comply with regulatory or environmental conditions. As these projects are undertaken to maintain current storage capabilities, the new assets are allocated between the regulated and unregulated storage operations based on the allocations of the original asset.

3) New storage asset to replace and enhance existing asset

   These projects consist of storage-related assets that replace existing storage assets and provide incremental storage capacity or deliverability. Under this category, there can be a further two scenarios:

      a) the new asset is replacing and enhancing an existing asset that is at the end of its useful life; or

b) the new asset is replacing and enhancing an existing asset that is not at the end of its useful life.

Under the first category, the replacement of the existing utility asset is driven by the need to replace the existing asset which has reached the end of its useful life, and not by the desire to increase storage capacity and deliverability to service the ex-franchise customers. As a result, the cost of replacing the existing asset is allocated between the regulated and unregulated storage operations based on the historic allocation of asset being replaced, without enhancements to capacity or deliverability, and the incremental cost of enhancing the asset is allocated to the unregulated business.

Under the second category, the replacement of the existing utility asset is driven by the desire to increase storage capacity and deliverability for the unregulated operations. As the replacement of the asset would not have occurred if not for the operation needs of the unregulated operations, the cost of the entire replacement asset is allocated to the unregulated business.

Base pressure gas

Historical base pressure gas was allocated to the unregulated storage operations at legacy UG as part of the one-time separation and transfer of its storage assets existing at the time of the NGEIR decision, and legacy EGD agreed to allocate a portion of its historical base pressure gas to the unregulated storage operations as part of the 2016 rate case[13]. Additions and removals to the base pressure gas are allocated to the unregulated storage operations in proportion with the allocations of the relevant asset pools.

Proposal for harmonized EGI unregulated storage cost allocation methodology

The current treatment for new storage assets is aligned at legacy EGD and UG and appropriate as the methodology for new storage assets is consistent with the unregulated storage cost allocation studies approved by the OEB.

No additional methodology updates are required for EGI in this area going forward.

Impact

No quantitative impact.

B. New General Plant Assets

General plant assets relate to assets used in the utility's general plant facilities. General plant assets are capital assets used to support day-to-day business and operations activities but are not specified assets used solely in distribution, transmission, or storage systems. These assets include land and buildings, computer software and hardware, tools and equipment, transportation and heavy-work equipment, natural gas vehicle fuel equipment and communication equipment.

[13] EB-2015-0114 – Decision and Interim Rate Order (December 10, 2015)

The current definition of general plant assets differs between legacy EGD and UG with respect to the inclusion of head office buildings and land. At legacy UG, head office buildings are designated as general plant assets that support their storage, transmission and distribution businesses, whilst at legacy EGD, head office buildings are designated as distribution assets rather than general plant assets.

Legacy UG unregulated storage cost allocation methodology summary

New general plant assets are allocated to the unregulated storage business annually, by applying two different allocators to the new general plant assets added within the year: one for vehicles and heavy work equipment, and another for all other general plant assets. General plant assets at legacy UG include IT software, office buildings and land, office equipment, vehicles and heavy work equipment.

a) Vehicles and heavy work equipment

   Vehicles and heavy work equipment are attributed to the unregulated storage operations in a multistep process. Firstly, a storage and transmission operations asset allocator is calculated based on the proportion of storage and transmission vehicles and heavy equipment assets (current year gross value) to the total vehicles and heavy equipment assets (current year gross value) used in legacy UG's operations. Next, a composite allocator derived from storage space, deliverability and horsepower is applied to the storage and transmission asset allocator described above, and that product is applied to the value of new vehicles and heavy work equipment in order to calculate the portion of new assets that are attributed to the unregulated storage operations. Refer to *Appendix B* for details on the calculation of the allocator described above.

b) All other general plant assets (general plant assets other than vehicles and heavy work equipment)

   Allocations for all other new general plant assets are based on a composite allocator derived from asset information and O&M expenses. The asset information used in the allocation is based on the gross total value of unregulated storage plant as a percentage of the total company gross plant value (both values excluding construction work in progress, asset retirement obligations and general plant). The O&M expense information used in the allocation is based on O&M expenses related to unregulated storage operations as a percentage of total company net O&M expenses. The asset and O&M expense allocators are averaged in equal portions to generate the composite factor used to allocate new general plant asset additions to the unregulated business. Refer to *Appendix B* for details on the calculation of the allocator described above.

   As the allocation to the unregulated storage operations is not tracked on an individual asset basis, general plant assets are treated as a pool for the purposes of the annual allocations described above. New additions to general plant assets are allocated using the allocators described above and added to the pool of unregulated general plant assets.

Legacy EGD unregulated storage cost allocation methodology summary

Legacy EGD does not currently allocate any general plant assets to the unregulated storage operations.

Proposal for harmonized EGI unregulated storage cost allocation methodology

Allocation methodology

EGI will allocate a portion of its new general plant assets to the unregulated storage operations on a monthly basis going forward, using the legacy UG method of determining the allocations with slight modifications to better align the harmonized methodology for EGI within the framework of the design principles. Allocation of general plant assets to the unregulated storage business is fair as the purpose of general plant assets is to support day-to-day operations, which includes storage operations. The legacy UG methodology to allocate a portion of new general plant assets to the unregulated storage business is supported by UG's board-approved 2007 cost allocation study[14] and board-approved 2011 and 2013 independent unregulated storage cost allocation studies[15, 16].

The refined methodology will result in the following change to the existing legacy UG methodology for allocation of new general plant asset additions in the year:

- All new general plant assets, including vehicle and heavy work equipment will be allocated using one allocator (Refer to *Appendix B* for details of the calculation of the allocator)

As EGI, total EGI O&M expenses will be used to determine the allocators for the legacy entities. The modified legacy UG methodology continues to maintain a fair allocation that represents underlying business activities, whilst simultaneously streamlining the cost allocation methodology related to general plant assets. The current allocator for vehicles and heavy equipment, using a composite of capacity, storage and horsepower, is overly complex and not easily traceable or reproducible by other parties. Replacing this allocator with the simpler general plant allocation method will increase transparency of the vehicles and heavy equipment asset allocations to unregulated storage, in line with design principles.

General plant assets definition

A harmonized definition of general plant assets for the purposes of unregulated storage allocations will be required at EGI. The inclusion of head office buildings and land in the definition of general plant assets, and the determination to allocate a portion to the unregulated storage business is supported by UG's board-approved 2007 cost allocation study[17] and board-approved 2011 and 2013 independent unregulated storage cost allocation studies[18,19].

To ensure consistency of the general plant asset definition between the two legacy entities, EGI will include the following EGD assets as general plant assets for the purpose of determining allocations to the unregulated operations from an asset perspective as well as for the related depreciation and property tax expense allocations:

[14] KPMG Report for Union Gas – Unregulated Operations Accounting and Reporting Documentation (May 14, 2008)
[15] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[16] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[17] KPMG Report for Union Gas – Unregulated Operations Accounting and Reporting Documentation (May 14, 2008)
[18] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[19] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review

- Administrative buildings and accompanying land, which currently includes: Markham – Technology & Operations Centre, Ottawa – Conventry Road, Thorold – Schmon Parkway and North York – Victoria Park Complex

Legacy EGD: One-time split for existing general plant assets

Legacy EGD does not currently allocate any general plant assets to the unregulated storage operations. Given that EGI will be allocating general plant assets to the unregulated storage operations going forward, legacy EGD will perform a one-time allocation of its existing general plant assets as at December 31, 2020 (or at a future date to be determined by management dependent on the timing of the new harmonized methodology implementation) to the unregulated storage operations. The existing legacy EGD general plant assets will be assigned to the unregulated storage function using legacy EGD O&M expense information in a manner consistent with the EGI methodology described above.

Impact

See below for unregulated general plant asset balances under current and proposed harmonized EGI unregulated storage cost allocation methodology. All amounts are based on 2020 budgeted figures.

	Unregulated General Plant Asset Balance (Net)		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage assets)
EGD	-	$2.48M	+ $2.48M
UG	$7.35M	$6.93M	- $0.42M
EGI	**$7.35M**	**$9.41M**	**+ $2.05M***

*Difference of $0.01M due to rounding

C. Cost of Gas

Both legacy EGD and UG incur unregulated storage gas costs related to lost and unaccounted for gas, fuel consumed to move gas (compressor fuel), customer-supplied fuel and external storage costs related to purchasing storage space from third parties. Lost and unaccounted for gas includes all components of gas loss, such as leakages, venting, meter errors and other similar considerations.

Allocators are required for both lost and unaccounted for gas and fuel used to move gas as these costs are related to both regulated and unregulated storage activities. No allocator is required for customer-supplied fuel and external storage costs related third-party storage, as these are driven by services, activities and contracts which are either exclusively regulated or exclusively unregulated.

Legacy UG unregulated storage cost allocation methodology summary

Lost and unaccounted for gas ("UFG")

Unaccounted for gas ("UFG") at legacy UG relates to gas losses from storage and transportation. Total actual unaccounted for gas incurred is allocated to the unregulated storage operations on an annual basis using a volumetric allocator based on actual gross unregulated storage activity as a percentage of total actual gross storage and transportation activity. Gross activity is the sum of absolute volumes as it relates to both injections and withdrawals (i.e., 100GJ injections and 100GJ of withdrawals = 200GJ of gross activity). Refer to *Appendix C* for details on the calculation of the allocation described above.

Fuel consumed to move gas (compressor fuel)

Total actual fuel consumed is allocated to the unregulated storage operations daily using a volumetric allocator based on net daily unregulated storage activity as a percentage of net daily total activity for storage and transportation. Net activity is composed of injections less withdrawals (i.e., 100GJ injections and 100GJ of withdrawals = 0GJ of net activity). Refer to *Appendix D* for details on the calculation of the allocation described above.

Legacy EGD unregulated storage cost allocation methodology summary

Lost and unaccounted for gas ("LUF")

Lost and unaccounted for gas ("LUF") at legacy EGD relates to gas losses from storage operations (as opposed to storage and transportation operations at legacy UG). Expected annual lost and unaccounted for gas volumes for storage operations were determined to be 23,763.6 10^3m^3 or about 0.835 bcf[20]. The total LUF provision has not been updated since before the commencement of legacy EGD's unregulated storage business. Currently, 14.3%[21] of the total LUF provision for storage (0.12 bcf) is designated as being related to the unregulated storage operations, based on volumetric drivers for storage capacity measured in 2015, and the capacity-based allocator used to determine the LUF related to the unregulated storage operations has not been updated with current capacity.

The 0.12 bcf of LUF associated with the unregulated storage business is applied to the Quarterly Rate Adjustment Mechanism ("QRAM") reference price of gas to determine the cost.

Refer to *Appendix C* for details on the calculation of the allocation described above.

Fuel consumed to move gas (compressor fuel)

Total actual storage fuel consumed is allocated to the unregulated storage operations on a monthly basis. The unregulated portion is calculated by first determining a compressor fuel consumption percentage (total fuel consumed for storage as a percentage of total monthly storage activity, represented as the difference between the opening and closing balance), and applying that fuel consumption percentage to the monthly unregulated activity (represented as the difference between the opening and closing unregulated balance). Refer to *Appendix D* for details on the calculation of the allocation described above.

Proposal for harmonized EGI unregulated storage cost allocation methodology

In determining the harmonized EGI unregulated storage cost allocation methodology, management considered aligning the volumetric activity basis (gross activity as opposed to net activity), used to allocate the two gas costs as well as the frequency at which the allocations of volumetric activity will be presented (monthly activity as opposed to daily activity). Due to the nature of the fuel consumption and use of counteracting fuel movement within the storage operations, management determined that

[20] EB-2015-0114, Exhibit A1, Tab 5, Schedule 1, Page 3 of 6
[21] EB-2015-0114, Exhibit A1, Tab 5, Schedule 1, Page 2 of 6

different bases for allocation of the two gas costs to the unregulated storage business as outlined below would more accurately attribute costs between the unregulated and regulated operations.

Lost and unaccounted for gas

EGI will allocate lost and unaccounted for gas to the unregulated storage business on a monthly basis using actual gross unregulated storage activity as a percentage of total actual gross activity consistent with the operations contributing to the total lost and unaccounted for gas volume (i.e., total actual gross activity for storage and transportation is used to allocate UFG, as it relates to gas losses from storage and transportation operations; total actual gross activity for storage is used to allocate LUF, as it relates to gas losses from storage operations). This methodology is consistent with the legacy UG allocation methodology with a slight modification to better align the harmonized methodology for EGI within the framework of the design principles. The legacy UG methodology is supported by the cost allocation studies[22,23,24] previously reviewed and approved by the OEB[25].

The revision to the methodology is related to the basis for which the volumetric gross activity is being determined. Legacy UG previously performed the allocation of lost and unaccounted for gas once a year using volumetric activity for the entire year. Going forward, EGI will be performing allocations using volumetric activity by month, to consider activity fluctuations throughout the year and to provide a more accurate cost for lost and unaccounted for gas, given gas reference price fluctuations. This enhances cost causality and is in line with the methodology design principles. Furthermore, using monthly activity as a basis for allocation to the unregulated operations is in line with EGI's process of recording monthly entries into the financial systems.

Refer to *Appendix C* for details on the calculation of the allocation described above.

Fuel consumed to move gas (fuel consumed)

EGI will allocate fuel consumed to the unregulated storage business on a monthly basis using actual net unregulated storage activity as a percentage of total actual net storage activity. The allocation of fuel consumed to the unregulated storage operations will be determined on a daily basis (daily fuel consumed will be allocated to the unregulated storage operations based on daily net activity). This methodology is consistent with the legacy UG allocation methodology per the cost allocation studies[26,27] previously reviewed and approved by the OEB[28].

Refer to *Appendix D* for details on the calculation of the allocation described above.

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[22] KPMG Report for Union Gas – Unregulated Operations Accounting and Reporting Documentation (May 14, 2008)
[23] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[24] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[25] EB-2011-0038 – Decision and Order (January 20, 2012)
[26] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[27] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[28] EB-2011-0038 – Decision and Order (January 20, 2012)

Impacts

See below for cost of gas expenses under current and proposed harmonized EGI unregulated storage cost allocation methodology. All amounts are based on 2020 budgeted figures.

	Unregulated Storage Lost and Unaccounted for Gas Expense		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	$0.50M	$0.54M	+ $0.04M
UG	$1.83M	$1.76M	- $0.06M*
EGI	**$2.33M**	**$2.30M**	**- $0.02M**

* Difference of $0.01M due to rounding

	Unregulated Storage Fuel Consumed to Move Gas (Fuel Consumed) Expense		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	$0.46M	$0.24M	- $0.22M
UG	$2.43M	$2.43M	-
EGI	**$2.89M**	**$2.67M**	**- $0.22M**

D. Operating & Maintenance Expenses

Operating and maintenance (O&M) expenses represent expenses incurred to operate and maintain all EGI natural gas distribution, storage and transmission activities. These expenses can be directly or indirectly attributable to the storage operations and are incurred by EGI or by Corporate.

The components to address O&M cost allocations to the unregulated storage business are:

1) O&M: Storage Operations
2) O&M: Storage Support Costs Related to Administrative and General Activities, and Corporate Administrative and General Overheads
3) O&M: Variable Storage Support Costs

1. O&M: Storage Operations

Legacy UG unregulated storage cost allocation methodology summary

Legacy UG organizes its expense in internal work orders (known as IOs), and the IOs are categorized based on the underlying activity for the purposes of allocating costs to the unregulated storage operations.

Table 1: O&M Expense Classification Categories for Storage Operations

O&M Classification	Description
Storage-General	Underlying activity related to storage operations
Storage-Shared	Underlying activity related to storage and transmission operations
Storage-Unregulated	Underlying activity related to unregulated storage operations
Storage-Regulated	Underlying activity relating to regulated storage operations
Storage-Support	Underlying activity supports storage operations and all other operations

O&M expenses directly related to storage operations at legacy UG are classified under the following O&M classification categories: Storage-General, Storage-Shared, Storage-Unregulated, and Storage-Regulated. IOs under Storage-General and Storage-Shared are further categorized by asset-related categories to enable the allocation: Supervision, wells, lines, compressors, measuring and regulating equipment (M&R), dehydration, rents and others. Allocations classified as Storage-Support are described in Section 2 below (O&M: Storage Support Costs Related to Administrative and General Activities, and Corporate Administrative and General Overheads).

Allocations are not required for Storage-Unregulated and Storage-Regulated categories as these costs capture operating and maintenance expenses that can be traced directly to either the regulated or unregulated storage operations.

The expenses categorized under Storage-General and Storage-Shared are incurred to operate and maintain storage assets utilized to provide storage services for both the unregulated and regulated storage operations, as well as transmission services in the case of Storage-Shared. As a result, allocations are required to identify the costs related to the unregulated storage operations. These allocations to the unregulated storage operations are performed based on the underlying asset for which the expenses are incurred to support. The underlying asset percentage allocations (unregulated storage assets as a percentage of total storage assets) for each storage asset category at each individual storage pool is updated annually, for the purposes of O&M allocations.

Refer to *Appendix E* for details on the allocation described above.

Legacy EGD unregulated storage cost allocation methodology summary

Legacy EGD incurs operating and maintenance costs for its unregulated storage operations mostly through its integrated storage operation, although certain costs can be directly related to its unregulated storage operations. Legacy EGD performs cost allocations from its integrated storage operations for its unregulated storage operations on a monthly basis, using allocators with both a fixed and variable component. Fixed activity allocators are determined for each cost element (i.e., contract services, materials and supplies) based on three activity drivers:

- Capacity: An annual component for space or capacity, derived from storage models[29]

[29] EB-2011-0354, Exhibit D2, Tab 5, Schedule 1, Black & Veatch Independent Review – Page 26 of 53

- Commodity: A variable component for each unit of gas injected into or withdrawn from storage[30]
- Deliverability: A peak component for the maximum daily rate at which the gas may be withdrawn from storage[31]

The variable portion of the allocator considers the activity drivers (listed above) expected to be related to unregulated or regulated storage operations for the current period; capacity and deliverability are updated periodically, and commodity is updated monthly.

Refer to *Appendix E* for details on the allocation described above.

Proposal for harmonized EGI unregulated storage cost allocation methodology

EGI will allocate its O&M costs directly related to storage operations based on the proportion of underlying storage assets assigned to the unregulated storage operations (which is updated on an annual basis) following the legacy UG approach with slight modifications to better align the harmonized methodology for EGI within the framework of the design principles. The legacy UG methodology is consistent with the storage unregulated cost allocation methodology per the cost allocation studies[32,33] previously reviewed and approved by the OEB[34]. Further, the fixed activity allocator used at legacy EGD incorporated management estimates, and thus was less transparent to other parties. Therefore, an asset-based allocation that can be readily traced to the assets supporting the unregulated storage operations will further increase transparency and enhance the causation linkage within the allocation methodology.

The refined methodology will result in the following change to the existing legacy UG methodology for the allocation of O&M expenses directly related to storage operations:

- O&M costs will continue to be classified into asset-specific cost pools and will be allocated using the storage asset category. However, asset-specific cost pools will now be allocated using a storage asset allocator averaged across all asset locations for each asset category (as opposed to allocators being calculated by location for each asset).

The modified legacy UG methodology continues to maintain a fair allocation that represents underlying business activities, whilst simultaneously streamlining the cost allocation methodology related to O&M expenses directly related to storage operations. Using one allocator per storage asset category across the various storage pool locations will increase the transparency of the allocations and allow outside parties to more easily reproduce the allocator, in line with design principles.

Impact

See below for the O&M: Storage operations expenses under current and proposed harmonized EGI unregulated storage cost allocation methodology. All amounts are based on 2020 budgeted figures.

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[30] EB-2011-0354, Exhibit D2, Tab 5, Schedule 1, Black & Veatch Independent Review – Page 26 of 53
[31] EB-2006-08-25, Exhibit G2, Tab 1, Schedule 1, Page 16 of 26
[32] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[33] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[34] EB-2011-0038 – Decision and Order (January 20, 2012)

	Unregulated Storage O&M: Storage Operations Expense		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	$1.63M	$2.63M	+ $1.00M
UG	$3.92M	$3.80M	- $0.12M
EGI	**$5.55M**	**$6.43M**	**+ $0.88M**

2. O&M: Storage Support Costs related to Administrative and General Activities, and Corporate Administrative and General Overheads

Legacy UG unregulated storage cost allocation methodology summary

O&M expenses related to administrative and general activities that support storage operations at legacy UG are classified under the Storage-Support O&M classification bucket listed out in **Table 1**. Administrative and general activities include support from IT, Finance, HR and other administrative areas, as well as the net Corporate overhead allocation charges. These administrative and general expenses are allocated in proportion to UG's unregulated storage O&M expenses (O&M expenses related to unregulated storage operations as a percentage of total company net O&M expenses). Refer to *Appendix F* for details on the calculation of the allocation described above.

Legacy EGD unregulated storage cost allocation methodology summary

Labour expenses for salary staff within storage operations is marked up to account for administrative and general overheads, which include Enbridge corporate overheads as well as performance-based compensation that is included as part of Enbridge's employee compensation plan. An overhead markup of 65% to 70% has been applied to the total integrated storage operation labour expenses, which is then allocated to unregulated storage using the fixed and variable volume activity allocators described under EGD's current state treatment for O&M storage costs. Refer to *Appendix F* for details on the calculation of the allocation described above.

Proposal for harmonized EGI unregulated storage cost allocation methodology

EGI will allocate actual administrative and general O&M support costs (excluding the variable O&M support costs documented in Section 3 below) in proportion with O&M expenses incurred by the unregulated storage operations following a modified legacy UG approach.

Currently, O&M support costs are allocated based on the total unregulated storage operations O&M costs as a percentage of total O&M costs (including O&M support costs). Going forward, EGI will exclude O&M costs related to storage support from the determination of the allocator to be applied to storage support departments. Refer to *Appendix F* for details on the calculation of the allocation described above.

The legacy UG approach is consistent with the unregulated storage cost allocation methodology studies[35,36] previously reviewed and approved by the OEB[37]. The legacy UG approach of allocating actual administrative and general O&M costs results in increased traceability of costs as compared to the approved legacy EGD methodology of marking up labour expenses to account for administrative and general overhead costs. The proposed modification to the existing legacy UG methodology further enhances accuracy of the storage support allocations, as it will remove O&M support costs in the determination of the allocator that is used to allocate O&M support costs to unregulated storage.

Impact

See below for the O&M: Storage support costs related to administrative and general activity expenses under current and proposed harmonized EGI unregulated storage cost allocation methodology. All amounts are based on 2020 budgeted figures.

	Unregulated Storage O&M: Storage Support Costs (Related to Administrative and General Activity) Expense		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	$0.47M	$3.58M	+ $3.11M
UG	$5.83M	$3.78M	- $2.05M
EGI	**$6.30M**	**$7.36M**	**+ $1.06M**

3. O&M: Variable Storage Support Costs

Legacy UG unregulated storage cost allocation methodology summary

There are storage support areas that can vary in terms of the support that they provide to the storage business year to year. For instance, the Business Development group would be involved to the extent of planning or development of an unregulated storage asset. If there were no upcoming unregulated storage projects for the year, their involvement would be negligible. Other variable storage support groups include asset management, lands and permitting, engineering, and regulatory affairs.

At legacy UG, these department IOs are a subcategory of the Storage-Support O&M classification bucket listed out in **Table 1**. The costs incurred under these areas for a given year are based on activities to be conducted by the departments.

Please refer to *Appendix G* for a list of the departments identified to provide variable support to the unregulated storage operations.

[35] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[36] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[37] EB-2011-0038 – Decision and Order (January 20, 2012)

Legacy EGD unregulated storage cost allocation methodology summary

As discussed above, legacy EGD applies a general markup to costs and therefore does not determine the separate cost associated with storage support activities.

Proposal for harmonized EGI unregulated storage cost allocation methodology

EGI will allocate variable storage support O&M costs in accordance with the activities to be conducted by these departments, consistent with the existing legacy UG methodology. Activity templates will be completed by these departments on an annual basis to determine expected unregulated activities.

Based on discussions with management over the nature of the support provided by these departments, the use of activity templates correlates the nature of the cost to the type of storage operation to ensure costs (unregulated or regulated) are allocated appropriately. The legacy UG approach is consistent with the storage unregulated cost allocation methodology per the cost allocation studies[38,39] previously reviewed and approved by the OEB[40].

Impact

See below for the O&M: Variable storage support expenses under current and proposed harmonized EGI unregulated storage cost allocation methodology. All amounts are based on 2020 budgeted figures and activity templates completed in 2020.

	Unregulated Storage O&M: Variable Storage Support Expense		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	-	$0.43M	+ $0.43M
UG	$1.37M	$1.37M	-
EGI	**$1.37M**	**$1.80M**	**+ $0.43M**

E. Depreciation Expense

Depreciation expense is calculated on the asset balances allocated to the unregulated storage business, which include storage assets and general plant assets.

Legacy EGD and UG unregulated storage cost allocation methodology summary

Depreciation expense: Storage assets

The determination of the depreciation expense related to storage assets allocated to the unregulated business is aligned at the legacy entities. The annual depreciation rates for underground storage assets were approved by the Board in 2013 and 2014 for UG and EGD. respectively. Depreciation expense (and accumulated depreciation amount) is calculated at the individual asset level using the applicable rates

[38] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[39] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[40] EB-2011-0038 – Decision and Order (January 20, 2012)

for the storage class. See *Appendix H* for the annual depreciation rates for the unregulated storage assets.

Depreciation expense: General plant assets

The determination of depreciation expense related to general plant assets allocated to the unregulated business was only applicable to legacy UG, as legacy EGD has not allocated general plant assets to its unregulated storage operations. Due to the nature of general plant assets and the complexity involved in individually tracking general plant assets, the depreciation expense related to the general plant assets is allocated to the unregulated storage in the same proportion of unregulated general plant assets to total general plant assets (using the two general plant asset allocators described in the *New General Plant Assets* section above).

Proposal for harmonized EGI unregulated storage cost allocation methodology

Depreciation expense: Storage assets

The current treatment for storage asset depreciation is aligned at legacy EGD and UG and appropriate as the methodology for new storage assets is consistent with the unregulated storage cost allocation studies approved by the OEB.

No additional methodology updates are required for EGI in this area.

Depreciation expense: General plant assets

EGI will be adopting the legacy UG method of allocating depreciation expense related to general plant assets (using the general plant allocator used to allocate new general plant assets to the unregulated storage operations). As a result of the adoption, EGI will have an aligned methodology when incurring depreciation expense for general plant assets. This is appropriate given that this method is consistent with the storage unregulated cost allocation methodology per the cost allocation studies[41,42] previously reviewed and approved by the OEB[43].

Impact

See below for the depreciation expense related to general plant assets under current and proposed harmonized EGI unregulated storage cost allocation methodology. All impacts to depreciation expense are related to general plant assets, as there was no quantitative impact relating to depreciation expense related to storage assets. All amounts are based on 2020 budgeted figures.

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[41] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[42] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[43] EB-2011-0038 – Decision and Order (January 20, 2012)

	Unregulated Storage Depreciation Expense (Related to General Plant Assets)		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	-	$1.16M	+ $1.16M
UG	$1.33M	$1.33M	-
EGI	**$1.33M**	**$2.49M**	**+ $1.17M***

* Difference of 0.01M due to rounding

F. Property Tax

Property tax is the levy issued by the government based on the current use and value of the property. Legacy EGD and UG pay property taxes on their wells, lines, buildings, compressors and land.

Legacy UG unregulated storage cost allocation methodology summary

On an annual basis, actual property taxes related storage assets are allocated to UG's unregulated storage operations based on the proportion of unregulated storage assets (excluding general plant assets) to total storage assets.

Property tax related to general plant assets is allocated to the unregulated storage operations using the same allocator used to allocate new general plants.

Legacy EGD unregulated storage cost allocation methodology summary

At legacy EGD, property taxes are allocated to the unregulated storage operations based on a combination of fixed and variable activity allocators for capacity and deliverability. As there are no general plant assets allocated to the unregulated business, there is no allocation for property taxes related to the general plant assets.

Proposal for harmonized EGI unregulated storage cost allocation methodology

EGI will allocate property taxes related to storage assets based on the underlying storage assets, in accordance with the legacy UG method. EGI will also allocate property tax related to general plant assets on a monthly basis using the same allocator used to allocate new general plant assets, in accordance with the legacy UG methodology. EY has observed that the underlying assets are a direct driver of property taxes and therefore, this is appropriate and consistent with the guiding principles previously outlined. The harmonized approach is consistent with the storage unregulated cost allocation methodology per the cost allocation studies[44,45] previously reviewed and approved by the OEB[46].

[44] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[45] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[46] EB-2011-0038 – Decision and Order (January 20, 2012)

Impact

See below for the property tax expenses under current and proposed harmonized EGI unregulated storage cost allocation methodology. All impacts related to legacy UG are related to general plant assets allocators, as there will no longer be a separate allocator for vehicles and heavy work equipment (as described in Section B above). All amounts are based on 2020 budgeted figures.

	Unregulated Storage Property Tax Expense (Storage Assets)		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	$0.28M	$0.30M	+ $0.01M*
UG	$1.44M	$1.44M	-
EGI	**$1.72M**	**$1.74M**	**+$ 0.01M***

* Difference of 0.01M due to rounding

	Unregulated Storage Property Tax Expense (General Plant Assets)		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	-	$0.01M	+ $0.01M
UG	$0.03M	$0.02M	- $0.01M
EGI	**$0.03M**	**$0.03M**	**+ $0.01M ***

* Difference of 0.01M due to rounding

G. Cost of Unutilized In-Franchise Storage Capacity

Unutilized in-franchise (regulated) storage capacity can be defined as the difference between the amount of storage reserved for in-franchise customers and the amount required by in-franchise customers. The portion of storage capacity that is not being used by in-franchise customers is made available to ex-franchise (unregulated) customers for short-term storage. As such, the costs associated with the unutilized capacity are assigned to the unregulated storage operations, and actual net revenues from the excess capacity must be compared with the net revenues expected during rate application to ensure there is no cross subsidization or recovery by ratepayers.

Legacy UG unregulated storage cost allocation methodology summary

Storage reserved for in-franchise customers at legacy UG is set at 100PJ[47] per the NGEIR decision, and the amount required by in-franchise customers is updated every year. For 2019, the storage capacity required for UG's in-franchise customers was 97PJ. As UG's rates were last determined in 2013 with the assumption that the in-franchise customers would require 89PJ of storage capacity, the difference in

[47] EB-2005-0551, Decision with Reasons, Page 83

expected revenues and costs related to actual short-term unregulated storage sales must be determined.

Legacy EGD unregulated storage cost allocation methodology summary

There is no unutilized in-franchise storage capacity at legacy EGD.

Analysis

As there is no unutilized in-franchise storage capacity at legacy EGD, no harmonized EGI methodology is required. The existing methodology in use at legacy UG is consistent with the unregulated storage cost allocation studies[48,49] approved by the OEB[50].

Proposed for harmonized EGI unregulated storage cost allocation methodology

No immediate harmonization activities are required for EGI going forward.

Impact

No quantitative impact.

H. Interest Expense on Long-Term Debt

Interest expense related to long-term debt is incurred to fund capital expansion.

Legacy EGD and UG unregulated storage cost allocation methodology summary

Interest expense related to long-term debt for EGI will be appropriately allocated to regulated and unregulated activities through rate setting and earning sharing mechanisms. Commencing with the 2019 earning sharing calculation, the allocation of interest expense related to long-term debt to the unregulated storage business has been aligned at the two legacy entities, following the legacy UG methodology.

EGI calculates Rate Base on an average of monthly averages basis for each the regulated and unregulated segments of the business (with the regulated segment being utilized for rate setting/earning sharing mechanism purposes). Similarly, the effective cost of long-term debt over the year is also calculated on an average of monthly averages basis, reflecting that debt issuances and retirements in the year are partially effective. The split of regulated and unregulated Rate Base as a percentage of total Rate Base is then applied to the effective cost of long-term debt, and the unregulated amount is excluded from utility results. For example, if Rate Base is 90% regulated and 10% unregulated, then EGI would apportion 10% of its effective long-term debt costs to the unregulated business, consistent with unregulated Rate Base, to be excluded from utility results.

[48] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[49] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[50] EB-2011-0038 – Decision and Order (January 20, 2012)

Proposal for harmonized EGI unregulated storage cost allocation methodology

The treatment of interest expense for long-term debt is expected to be aligned at legacy EGD and UG as part of the 2019 earnings sharing and deferral clearance application, in a manner that is consistent with the allocation methodology that has been utilized in previous regulatory filings to the OEB[51] by UG.

No additional methodology updates are required for EGI in this area going forward.

Impact

No quantitative impact.

I. Summary of Impact

See chart for a summary of changes under the current and proposed harmonized EGI unregulated storage cost allocation methodology. All amounts are based on 2020 budgeted figures.

Allocation Area	EGI Harmonized Allocation Methodology	Summary of Impact (+/- to unregulated storage operations)		
		Legacy EGD	Legacy UG	EGI
Assets				
Storage assets (net)	No change – methodology is aligned at the legacy entities	-	-	-
General plant assets (net)	Modified legacy UG method	+ $2.48M	- $0.42M	+ $2.05M[52]
Total assets		+ $2.48M	- $0.42M	+ $2.05M
Expenses				
Cost of gas: Lost and unaccounted for gas	Modified legacy UG method	+ $0.04M	- $0.06M	- $0.02M
Cost of gas: Fuel used to move gas	Legacy UG method	- $0.22M	-	- $0.22M
O&M: Storage operations	Legacy UG method	+ $1.00M	- $0.12M	+ $0.88M
O&M: Storage support – administrative and general	Modified legacy UG method	+ $3.11M	- $2.05M	+ $1.06M
O&M: Storage support – variable	Legacy UG method	+ $0.43M	-	+ $0.43M
Depreciation expense: Storage Assets	No change – methodology is aligned at the legacy entities	-	-	-
Depreciation expense: General Plant Assets	Legacy UG method	+ $1.16M	-	+ $1.17M[53]
Property tax expense: Storage Assets	Legacy UG method	+ $0.01M	-	+ $0.01M

[51] EB-2019-0105
[52] Difference of $0.01M due to rounding
[53] Difference of $0.01M due to rounding

Allocation Area	EGI Harmonized Allocation Methodology	Summary of Impact (+/- to unregulated storage operations)		
		Legacy EGD	Legacy UG	EGI
Property tax expenses: General Plant Assets	Legacy UG method	+ $0.01M	- $0.01M[54]	+ $0.01M[55]
Unutilized in-franchise capacity	No change – allocation area only applicable to legacy UG	-	-	-
Interest expense on long-term debt	No change – methodology will be aligned at the legacy entities by planned implementation date	-	-	-
Total expenses		+ $5.55M[56]	- $2.23M[57]	+ $3.32M

[54] Impact for legacy UG due to change in determination of general plant asset allocators
[55] Difference of $0.01M due to rounding
[56] Difference of $0.01M due to rounding
[57] Difference of $0.01M due to rounding

VI. Procedures Performed by EY in Providing Management Assistance

EY performed the following tasks to assist management in determining a harmonized cost allocation methodology for unregulated storage operations:

1. Obtained an understanding of the unregulated storage allocations at the legacy companies through interviews with key personnel, supported by review of existing documentation such as models, policies, processes to allocate costs, unregulated storage operation studies and OEB rate filings;

2. Identified key differences between the unregulated storage activities conducted at both legacy entities based on the understanding of current storage allocations;

3. Assisted management by identifying suggested alternatives for a harmonized methodology;

4. Assisted management in determining an appropriate harmonized methodology;

5. Assisted management in determining expected impact of modifications to cost allocation methodology; and

6. Worked collaboratively with the Company to assist in documenting an updated framework (including policies and processes) for unregulated storage allocations for the amalgamated Company.

VII. Summary of Observations

The harmonized EGI cost allocation methodology for unregulated storage that will be used by EGI includes assessment of cost drivers for allocation via management's analysis of assets, completion of the activity templates, and identification of related causality to unregulated activities. Based on EY's understanding of EGI's harmonized storage allocation process and methodology, the underlying methodologies and rationale described in Section V are generally consistent with previous OEB guidance and/or decisions in their treatment of storage related assets and expenses and continues to maintain and uphold the design principles. The methodologies chosen for each of the asset and expense areas are based on underlying assets and their respective activities.

As part of EY's procedures to gain an understanding of the current methodologies at the legacy entities through discussion with management, EY also observed the following:

- **O&M – Storage Operations**: Discussions with management and review of the existing classifications revealed that there were a limited number of O&M sub-classifications that were not currently being used (i.e., did not have IOs associated to the expense category). After further analysis and discussions, EGI revisited classifications of IOs to Storage-General – M&R to identify IOs capturing costs at locations that support both the storage and transmission operations, consistent with the underlying asset allocations. Eight IOs associated with four asset locations (Dow A Plant, Dawn 167, Edys Mills, and Oil Springs East) were reclassified from Storage-General – M&R to Storage-Shared – M&R. This reallocation resulted in a $25,679 decrease in costs associated to unregulated storage for 2019. Based on our understanding of the original cost allocation methodology and discussions with management about the functions of the underlying assets, the reclassification of the IOs attempts to better reflect the nature of costs incurred to support the unregulated operations.
- **O&M – Variable Storage Support**: As part of the discussions with management over the impact of operational and organizational changes resulting from the amalgamation, EGI identified an additional storage support department (Asset Management – Storage and Transmission) that would provide fluctuating levels of support to the unregulated storage operations. Management noted that this was an additional department that would be considered as a variable storage support area and would be completing activity templates going forward for the purposes of determining unregulated cost allocations. Based on our understanding of this department through discussions with management, the addition of that department is consistent with the harmonized EGI methodology.
- **Property Tax**: For the year ended 2019, approximately $27,000 in property taxes related to general plant assets at UG was not allocated to the unregulated business. It is suggested through designating overall accountability and oversight with respect to unregulated storage cost allocations, EGI will monitor the expense allocations made by the accountable parties for accuracy and timeliness. Furthermore, by establishing robust process and policy documentation for the new harmonized EGI methodology, EGI will enable outside parties to clearly understand the methods and calculations used in determining unregulated storage costs.

VIII. Appendices

A. Current State Materiality and Timing of Allocations

The chart below summarizes the 2019 unregulated actual asset and expense information for the purpose of understanding the materiality of the allocation areas, and the timing of the cost allocations. The chart below does not include expenses that do not require an allocator (i.e. customer supplied fuel, which are exclusively regulated or unregulated).

<table>
<tr><th rowspan="2">Allocation Area</th><th rowspan="2">Methodology Alignment</th><th colspan="2">2019 Unregulated Costs</th><th colspan="2">2019 Timing of Allocations</th></tr>
<tr><th>Legacy EGD</th><th>Legacy UG</th><th>Legacy EGD</th><th>Legacy UG</th></tr>
<tr><td>Assets</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>New storage assets (Net)</td><td>Aligned</td><td>$70.5M</td><td>$277.8M</td><td>Ad-hoc</td><td>Ad-hoc</td></tr>
<tr><td>General plant assets (Net)</td><td>Not aligned</td><td>-</td><td>$6.0M</td><td>N/A</td><td>Monthly</td></tr>
<tr><td>Total assets</td><td></td><td>$70.5M</td><td>$283.8M</td><td></td><td></td></tr>
<tr><td>Expenses</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Cost of gas: Lost and unaccounted for gas</td><td>Not aligned</td><td>$0.5M</td><td>$1.7M</td><td>Monthly</td><td>Annual</td></tr>
<tr><td>Cost of gas: Fuel used to move gas</td><td>Not aligned</td><td>$0.4M</td><td>$3.2M</td><td>Monthly</td><td>Annual</td></tr>
<tr><td>O&M: Storage operations</td><td>Not aligned</td><td rowspan="3">$2.7M</td><td rowspan="3">$15.9M</td><td>Monthly</td><td>Annual</td></tr>
<tr><td>O&M: Storage support – administrative and general</td><td>Not aligned</td><td>Monthly</td><td>Annual</td></tr>
<tr><td>O&M: Storage support – variable</td><td>Not aligned</td><td>N/A</td><td>Annual</td></tr>
<tr><td>Depreciation</td><td>Partially aligned</td><td>$1.9M</td><td>$9.0M</td><td>Monthly</td><td>Monthly</td></tr>
<tr><td>Property tax</td><td>Not aligned</td><td>$0.2M</td><td>$1.4M</td><td>Monthly</td><td>Annual</td></tr>
<tr><td>Unutilized in-franchise capacity</td><td>Aligned[58]</td><td>N/A</td><td>$(1.2)M</td><td>N/A</td><td>Annual</td></tr>
<tr><td>Total expenses</td><td></td><td>$5.7M</td><td>$30.0M</td><td></td><td></td></tr>
</table>

[58] Allocation area only applicable to legacy UG, therefore no further alignment is required

B. New General Plant Assets: Allocator Details

Legacy EGD and UG Allocators	
Legacy EGD:	N/A – no allocation
Legacy UG: For Vehicles and Heavy Work Equipment (V&HWE)	$\frac{\text{Gross S\&T V\&HWE}}{\text{Gross Total V\&HWE}} \times \left[\frac{(\text{STORAGEEXCESS+NETFROMSTOR})}{2} \times \text{HorsePower Allocator}\right]$
Legacy UG: For General Plant Assets	$\dfrac{\frac{\text{Gross unregulated storage assets (Excluding General Plant)}}{\text{Gross total plant (Excluding General Plant)}} + \frac{\text{Unreg O\&M costs}}{\text{Net O\&M costs for the company}}}{2}$

EGI Harmonized Allocator
EGI: For all General Plant Assets $\dfrac{\frac{\text{Gross unregulated storage assets (Excluding General Plant)}}{\text{Gross total plant (Excluding General Plant)}} + \frac{\text{Unreg O\&M costs}}{\text{Net O\&M costs for the company}}}{2}$

<u>Legend</u>:

- **STORAGEEXCESS**: Storage space allocator (in proportion to forecasted use of storage space)
- **NETFROMSTOR**: Storage deliverability allocator (in proportion to peak day demands from storage)
- **HORSEPOWER ALLOCATOR**: Allocates costs in proportion to the forecasted compression horsepower at Dawn required to provide S&T services on design day

C. Cost of Gas – Lost and Unaccounted for Gas: Allocation Details

Legacy EGD and UG Allocation	
Legacy EGD	Total LUF provision of 0.835 bcf × 14.3% unregulated storage capacity allocator
Legacy UG	$\frac{\text{Gross annual activity for unregulated storage}}{\text{Gross annual activity for total storage and transportation}} \times \text{Annual total UFG}$

EGI Harmonized Allocation
$\frac{\text{Gross monthly activity for unregulated storage}}{\text{Gross monthly activity for total storage (and transportation for legacy UG*)}} \times \text{Monthly lost and unaccounted for gas (LUF or UFG) [Note2]}$

<u>Legend:</u>

- **Gross activity**: Injections and withdrawals (i.e., 100GJ injections and 100GJ of withdrawals = 200GJ of gross activity)
- **UFG**: Unaccounted for gas at legacy UG representing gas losses from storage and transportation operations
- **LUF**: Lost and unaccounted for gas at legacy EGD representing gas losses from storage operations

<u>Note:</u>

1. Total lost and unaccounted for gas at legacy UG ("UFG") is calculated for storage and transportation operations, whereas total lost and unaccounted for gas at legacy EGD ("LUF") is for storage operations only. Therefore, the denominator in the allocator used at legacy UG will include transportation activity.
2. As the LUF provision at legacy EGD is an annual provision, the monthly LUF in the allocation illustrated above represents the annual LUF profiled throughout the year (initially profiled based on budget, and re-profiled using actuals at the end of the year).

D. Cost of Gas – Fuel Consumed to Move Gas: Allocation Details

Legacy EGD and UG Allocation	
Legacy EGD	$\frac{\text{Total monthly fuel consumed for storage}}{\text{OB monthly for the month} - \text{CB for the month}} \times (\text{Unreg storage monthly OB} - \text{Unreg storage monthly CB})$
Legacy UG	$\frac{\text{Net daily activity for unregulated storage}}{\text{Net daily activity for total storage}} \times \text{Daily fuel consumed}$

EGI Harmonized Allocation
$\frac{\text{Net daily activity for unregulated storage}}{\text{Net daily activity for total storage}} \times \text{Daily fuel consumed}$

Legend:

- **OB**: Opening storage balance
- **CB**: Closing storage balance
- **Net activity**: Injections less withdrawals (i.e., 100GJ injections and 100GJ of withdrawals = 0GJ of net activity)

E. O&M – Storage Operations: Allocation Details

Legacy EGD Allocation

O&M Expenses	Fixed Allocator	Variable Allocator
O&M expenses are organized into cost elements (i.e., labour, materials and supplies)	Fixed allocators are determined for each cost element, based on activity drivers: capacity, commodity and deliverability	Variable allocators are applied to allocate the costs between regulated and unregulated storage operations for each activity driver

Legacy UG Allocation and Harmonized EGI Allocation

O&M Classification	O&M Sub-Categorizations	Allocation Factor
Storage-General	Wells	Asset-based unregulated allocator for wells
	Lines	Asset-based unregulated allocator for lines
	Compressors	Asset-based unregulated allocator for compressors
	Measuring and Regulating (M&R)	Asset-based unregulated allocator for M&R
	Rents and Others	Weighted-average allocator for unregulated storage
Storage-Shared	Compressors	Asset-based unregulated allocator for compressors
	Measuring and Regulating (M&R)	Regulatory cost study – M&RRECL-PT
	Dehydration	Regulatory cost study – Dehydration Demand
	Supervision and Others	Regulatory cost study – O&M STO Split

<u>Regulatory Cost Study Allocators</u>:

1. STO O&M Split: This factor is calculated as the gross plant value of the unregulated assets as a percentage of the total company storage and transmission assets.

2. Dehydrator Demand: Allocates costs in proportion to dehydrator demand on design day.

3. M&RRECL-PT: Allocates costs in proportion to forecast storage and transmission activity at Dawn.

F. O&M – Storage Support (Administrative and General): Allocation Details

Legacy EGD and UG Allocation	
Legacy EGD	A markup of 65%-70% is applied to storage operation labour expenses to account for administrative and general storage support
Legacy UG	$\frac{\text{Unregulated O\&M Expenses}}{\text{Total Company Net O\&M Expenses}} \times$ O&M expenses related to Administrative & General Storage Support

EGI Harmonized Allocation
$\frac{\text{Unregulated O\&M Expenses (Excl. O\&M Storage Support)}}{\text{Total Company Net O\&M Expenses (Excl. O\&M Storage Support)}} \times$ O&M expenses related to Administrative & General Storage Support

G. O&M – Storage Support (Variable): Time Study Results

Group	Department	CC/IOs	O&M - Unreg %
Regulatory	Regulatory Applications & Strategy	IO312652	10%
		CC25240	10%
System Improvement	Lands, Permitting & Environment	IO340051	22%
		IO340052	22%
		IO340055	22%
		IO340056	22%
		IO340059	22%
		IO340060	22%
		IO340061	22%
		IO340062	22%
		IO340064	22%
		IO340065	22%
		IO340066	22%
		IO340067	22%
		IO340068	22%
		IO340100	22%
		IO340101	22%
		IO340104	22%
		IO340200	22%
		IO340201	22%
		IO340220	22%
		IO340221	22%
		IO340300	22%
		IO341200	22%
		IO341900	46%
		IO342400	46%
		IO343001	46%
		IO343160	22%
		IO343161	22%
		IO343162	22%
S&T Business Development	S&T Business Development Other	IO240892	20%
S&T Engineering	Underground Storage & Reservoir Engineering	CC25124	35%
		IO340037	35%
Asset Management	Storage Asset Management	CC25161, T161G	40%
		IO342675	40%
Core Projects	Project Design & Execution, Project Controls, Engineering Services	N/A – all capitalized 0%	

H. Depreciation Expense: Annual Depreciation Rates for Unregulated Storage Assets

Storage Asset Class	**EGD**	**UG**
Land Rights	1.16 %	2.10 %
Structures and Improvements	1.84 %	2.50 %
Wells	1.52 %	2.69 %
Well Equipment	5.56 %	2.05 %
Field Lines	1.49 %	2.48 %
Compressor Equipment	2.60 %	2.68 %
Measuring and Regulating Equipment	2.99 %	3.11 %

I. Details on Calculations for 2020 Impacts

Summary of 2020 Impacts
Unregulated Cost Allocation Harmonization
Enbridge Gas Inc.

Purpose: To summarize expected 2020 impacts as calculated in the individual tabs.

Allocation Area	Relevant Tabs	Current Methodology		Harmonized Methodology		Impact		
		A	B	C	D	E=C-A	F=D-B	E+F
		EGD	UG	EGD	UG	EGD	UG	EGI
Assets								
Storage Assets	N/A	Not Assessed - No Changes		Not Assessed - No Changes		-	-	-
General Plant Assets	**GP - UG; GP- EGD**	-	7,353,237	2,478,622	6,929,081	2,478,622	- 424,156	2,054,466
Total Assets						**2,478,622**	**- 424,156**	**2,054,466**
Expenses								
Cost of Gas: Lost and Unaccounted for Gas	**COG1 - UG; COG1 - EGD**	495,544	1,826,554	537,215	1,764,792	41,671	- 61,763	- 20,092
Cost of gas: Fuel used to Move Gas	**COG2 - EGD**	464,092	Not Assessed - No Changes	242,657	Not Assessed - No Changes	- 221,435	-	- 221,435
O&M: Storage Expenses	**O&M1**	1,627,959	3,922,812	2,631,015	3,799,239	1,003,057	- 123,573	879,484
O&M: Storage Support - Admin and general	**O&M2**	471,494	5,827,981	3,577,724	3,777,378	3,106,229	- 2,050,603	1,055,627
O&M: Storage Support - Variable	**O&M3**	-	1,370,658	434,096	1,370,658	434,096	-	434,096
Depreciation Expense: Storage Assets	N/A	Not Assessed - No Changes		Not Assessed - No Changes		-	-	-
Depreciation Expense: General Plant Assets	**DE - GP**	-	1,326,355	1,160,007	1,333,183	1,160,007	6,829	1,166,836
Property Tax: Storage Assets	**PT - Storage**	283,297	1,439,923	295,521	1,439,923	12,223	-	12,223
Property Tax: General Plant Assets	**PT - GP**	-	26,728	13,995	22,258	13,995	- 4,469	9,526
Unutilized in-franchise capacity	N/A	Not Assessed - No Changes		Not Assessed - No Changes		-	-	-
Total Expenses						**5,549,844**	**- 2,233,579**	**3,316,265**

Determining 2020 Impact
General Plant Assets
Legacy UG

Data Sources:
2020 Capital Asset Forecast
2018 Capital Asset PPE Schedule (Schedule 5)
2018 O&M data from the O&M team (SAP and Oracle)

New General Plant Assets for 2020 Under Harmonized Methodology

		Based on Actuals as at December 31, 2018
A	Total Gross Plant (Dec 31 - excluding WIP, ARO, and General Plant)	9,780,807,383
B	Total Unregulated Gross Storage (Dec 31 - excluding WIP, ARO and General Plant)	424,390,931
B / A = C	% Unregulated Storage to Total Plant	4.34%
D	UG Unregulated storage O&M costs	13,451,431
D	EGD Unregulated storage O&M costs	2,627,515
E	UG total net O&M costs for the company	461,872,369
E	EGD total net O&M costs for the company	468,081,238
m of D / Sum of E = F	O&M Storage Support Allocator	1.73%
(C+F) / 2 = G	**General Plant Allocation Factor**	**3.03%**

	AA	BB	CC	DD = BB+CC	EE = DD * G	FF=AA+BB
	Unregulated General Plant Assets: Beginning Balance as at Jan 1, 2020	**General Plant Asset: Additions (Based on 2+10 Forecast)**	**General Plant Assets: Retirements (Based on 2+10 Forecast)**	**General Plant Assets: Net New Assets (Based on 2+10 Forecast)**	**Unregulated General Plant Assets: Net New Assets (Based on 2+10 Forecast)**	**Unregulated General Plant Assets: Ending Balance, as at Dec 31, 2020**
Land	20,796	-	-	-	-	20,796
Structures & improvements	2,781,771	10,031,612	- 2,782,899	7,248,714	219,927	3,001,698
Office furniture & equipment	1,241,999	250,000	- 90,019	159,981	4,854	1,246,853
Office equipment - computers	3,248,619	52,160,464	- 18,470,351	33,690,114	1,022,162	4,270,781
Office Equipment - computers 10%	497,628	-		-	-	497,628
Transportation equipment	2,448,394	7,600,000	- 5,683,572	1,916,428	58,145	2,506,539
Heavy work equipment	741,627	-	- 736,705	- 736,705	- 22,352	719,275
Tools & work equipment	1,416,593	2,089,020	- 1,452,146	636,874	19,323	1,435,916
NGV Equipment	75,151	- 200,000	- 1,452,146	- 1,652,146	- 50,126	25,025
Communication equipment	536,840	138,687	- 379,283	- 240,596	- 7,300	529,540
Total	**13,009,418**	**72,069,784**	**- 31,047,120**	**41,022,664**	**1,244,632**	**14,254,051**

	GG	HH	II = GG+HH
	Unregulated General Plant Assets - Accumulated Depreciation: Beginning Balance, as at Jan 1, 2020	**Unregulated General Plant Assets - Change in Accumulated Depreciation (Based on 2+10 Forecast model)**	**Unregulated General Plant Assets - Accumulated Depreciation: Ending Balance, as at Dec 31, 2020**
Land	-	-	-
Structures & improvements	558,432	- 83,607	474,825
Office furniture & equipment	681,622	182,887	864,509
Office equipment - computers	2,568,113	- 181,615	2,386,498
Office Equipment - computers 10%	223,933	324,862	548,794
Transportation equipment	1,698,476	- 104,647	1,593,830
Heavy work equipment	192,176	146,724	338,901
Tools & work equipment	699,069	5,793	704,862
NGV Equipment	50,476	- 41,455	9,022
Communication equipment	320,814	82,915	403,729
Total	**6,993,111**	**331,858**	**7,324,969**

New General Plant Assets for 2020 Under Existing Methodology

	AA	JJ	KK	LL = JJ+KK	MM = AA+LL
	Unregulated General Plant Assets: Beginning Balance as at Jan 1, 2020	**Unregulated Additions to General Plant Assets (Based on 2+10 Forecast)**	**Unregulated Retirements (Based on 2+10 Forecast)**	**Net new Unregulated General Plant Assets - Gross**	**Unregulated General Plant Assets: Ending Balance, as at Dec 31, 2020**
Land	20,796	-	-	-	20,796
Structures & improvements	2,781,771	367,180	- 101,861	265,320	3,047,091
Office furniture & equipment	1,241,999	9,175	- 3,295	5,880	1,247,879
Office equipment - computers	3,248,619	1,897,929	- 676,057	1,221,872	4,470,490
Office Equipment - computers 10%	497,628	-	-	-	497,628
Transportation equipment	2,448,394	278,920	- 208,032	70,888	2,519,283
Heavy work equipment	741,627	-	- 26,965	- 26,965	714,662
Tools & work equipment	1,416,593	76,007	- 53,152	22,855	1,439,448
NGV Equipment	75,151	- 8,000	- 53,152	- 61,152	13,999
Communication equipment	536,840	4,430	- 13,883	- 9,453	527,387
Total	**13,009,418**	**2,625,641**	**- 1,136,396**	**1,489,245**	**14,498,663**

	NN	OO	PP = NN+OO
	Unregulated General Plant Assets - Accumulated Depreciation: Beginning Balance, as at Jan 1, 2020	**Unregulated General Plant Assets - Change in Accumulated Depreciation (Based on 2+10 Forecast model)**	**Unregulated General Plant Assets - Accumulated Depreciation: Ending Balance, as at Dec 31, 2020**
Land	-	-	-
Structures & improvements	558,432	- 100,943	457,489
Office furniture & equipment	681,622	182,339	863,961
Office equipment - computers	2,568,113	- 282,811	2,285,302
Office Equipment - computers 10%	223,933	324,862	548,794
Transportation equipment	1,698,476	- 139,849	1,558,627
Heavy work equipment	192,176	142,038	334,214
Tools & work equipment	699,069	- 3,217	695,852
NGV Equipment	50,476	- 50,631	- 155
Communication equipment	320,814	80,527	401,341
Total	**6,993,111**	**152,315**	**7,145,426**

Expected Impact for 2020 (+/- to unregulated business)

	JJ = FF-II	QQ =MM-PP	RR = JJ-QQ
	Under Harmonized Methodology	*Under Current Methodology*	
	Unregulated General Plant Assets - Net of Accumulated Depreciation: Ending Balance, as at Dec 31, 2020	**Unregulated General Plant Assets - Net of Accumulated Depreciation: Ending Balance, as at Dec 31, 2020**	**Impact**
Land	20,796	20,796	-
Structures & improvements	2,526,873	2,589,602	- 62,729
Office furniture & equipment	382,344	383,918	- 1,574
Office equipment - computers	1,884,283	2,185,189	- 300,906
Office Equipment - computers 10%	- 51,167	- 51,167	-
Transportation equipment	912,709	960,655	- 47,946
Heavy work equipment	380,375	380,448	- 73
Tools & work equipment	731,054	743,596	- 12,542
NGV Equipment	16,003	14,155	1,849
Communication equipment	125,811	126,046	- 235
Impact for 2020	**6,929,081**	**7,353,237**	**- 424,156**

Determining 2020 Impact
General Plant Assets
Legacy EGD

Data Sources:
2020 Capital Asset Forecast
2020 O&M Budget
2020 Unregulated Budget and LRP

Calculating One-Time Split as at Dec 31, 2020

		As at Dec 31, 2020 (Based on 2+10 forecast for assets, and 2020 Budget for O&M)
	Total Gross Plant (Dec 31 - excluding WIP, ARO, and General Plant)	10,221,798,024
	Adjustment for administrative buildings and accompanying land (considered general plant for the purposes of unregulated allocations)	
	Markham TOC	37,000,909
	Ottawa	11,737,671
	Thorold	16,272,082
	VPC	63,267,411
A	Adjusted Total Gross Plant (Dec 31 - excluding WIP, ARO, and General Plant)	10,093,519,951
B	Total Unregulated Gross Storage (Dec 31 - excluding WIP, ARO and General Plant)	120,526,051
B / A = C	% Unregulated Storage to Total Plant	1.18%
D	Unregulated storage O&M costs	3,227,660
E	Total net O&M costs for the company	460,877,268
D / E = F	O&M Storage Support Allocator	0.70%
(C+F) / 2 = G	**General Plant Allocation Factor**	**0.94%**
	2020 General Plant Assets - Gross PPE	679,597,766
	Adjustments for EGD:	
	Administrative buildings and accompanying land	
	Markham TOC	37,000,909
	Ottawa	11,737,671
	Thorold	16,272,082
	VPC	63,267,411
H	2020 General Plant Assets - Gross PPE adjusted for unreg allocation purposes	807,875,839
	2020 General Plant Assets - Accumulated depreciation	513,284,387
	Adjustments for EGD:	
	Administrative buildings and accompanying land	
	Markham TOC	5,850,165
	Ottawa	2,198,232
	Thorold	5,920,044
	VPC	16,860,957
I	2020 General Plant Assets - Accumulated depreciation adjusted for unreg allocation purposes	544,113,785
H-I = J	2020 General Plant Assets - Net	263,762,054
G * J = K	**2020 Unreg General Plant Assets - Net**	**2,478,622**

Determining 2020 Impact
Cost of Gas: Unaccounted for Gas
Legacy UG

Data Sources:
2020 Gas Supply Budget

Allocation for 2020 Under Harmonized Methodology

	2020 Budget	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
A	UFG Costs	1,543,409	1,395,471	1,310,171	937,984	706,546	616,559	681,679	706,235	673,341	777,231	1,079,961	6,328,791	16,757,378
B	Monthly %	13.7%	12.1%	9.1%	9.8%	9.6%	12.2%	10.7%	14.1%	12.2%	6.0%	8.9%	10.0%	10.5%
C = A*B	**Monthly $**	**211,447**	**168,852**	**119,226**	**91,922**	**67,828**	**75,220**	**72,940**	**99,579**	**82,148**	**46,634**	**96,117**	**632,879**	**1,764,792**

Allocation for 2020 Under Existing Methodology

	2020 Budget	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
A	UFG Costs	1,543,409	1,395,471	1,310,171	937,984	706,546	616,559	681,679	706,235	673,341	777,231	1,079,961	6,328,791	16,757,378
D	Annual %	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%
E = A*D	**Annual $**	**168,232**	**152,106**	**142,809**	**102,240**	**77,014**	**67,205**	**74,303**	**76,980**	**73,394**	**84,718**	**117,716**	**689,838**	**1,826,554**

Expected Impact for 2020 (+/- to unregulated business)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
C-E	**Impact for 2020**	**43,215**	**16,746**	**-23,583**	**-10,318**	**-9,185**	**8,015**	**-1,363**	**22,600**	**8,753**	**-38,084**	**-21,599**	**-56,959**	**-61,763**

Determining 2020 Impact
Cost of Gas: Fuel Consumed to Move Gas
Legacy EGD

Data Sources:
2020 Gas Supply Budget, including budgeted PGVA reference price
2020 January to April actual activity from Capacity Planning group

Allocation for 2020 Under Harmonized Methodology

A Budgeted PGVA Reference Price $ 163.52

	2020 Budget	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
B	2020 Fuel - Actuals (Jan-April) / Budget (May-Dec)	1,080	1,069	1,131	702	1,007	1,838	1,987	2,187	1,619	476	624	827	14,547
C	% Fuel Allocation to Unreg (Actual Jan-Apr 2020) - Note 1	0%	36%	3%	0%	-	-	-	-	-	-	-	-	-
D	% Fuel Allocation to Unreg (Actual 2019) - Note 1, 2	-	-	-	-	27%	5%	11%	11%	3%	30%	10%	0%	13%
E = B*C (Jan-Apr) E = B*D (May-Dec)	2020 Unregulated Fuel - Actuals (Jan-April) / Budget (May-Dec)	3	380	30	0	271	91	213	245	42	143	62	4	1,484
F = A*E	**Annual $**	**422**	**62,181**	**4,911**	**0**	**44,267**	**14,926**	**34,853**	**40,093**	**6,835**	**23,415**	**10,150**	**605**	**242,657**

Note 1: While the data is presented in a monthly format, the percentage allocators are calculated using net daily activity for the respective months.
Note 2: Fuel allocations for May to Dec 2020 are assumed to be comparable to May to Dec 2019 on a net daily basis, and as such, the 2019 Fuel Allocation % for these months are applied to 2020 budget for fuel.

Allocation for 2020 Under Existing Methodology

A Budgeted PGVA Reference Price $ 163.52

	2020 Budget	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
G	2020 Unregulated Fuel - Actuals (Jan-April) / Budget (May-Dec)	1	301	333	702	155	303	174	174	174	174	174	174	2,838
H = A*G	**Annual $**	**180**	**49,270**	**54,503**	**114,777**	**25,297**	**49,548**	**28,419**	**28,419**	**28,419**	**28,419**	**28,419**	**28,419**	**464,092**

Expected Impact for 2020 (+/- to unregulated business)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
C-E	**Impact for 2020**	**242**	**12,911**	**-49,592**	**-114,777**	**18,969**	**-34,623**	**6,433**	**11,673**	**-21,584**	**-5,005**	**-18,269**	**-27,815**	**-221,435**

Determining 2020 Impact
Cost of Gas: Lost and Unaccounted for Gas
Legacy EGD

Data Sources:
2020 Gas Supply Budget, including budgeted QRAM reference prices
2020 Jan-Apr actual volume activity from Capacity Planning group
2019 Actual Fuel Activity from Capacity Planning Group

Allocation for 2020 Under Harmonized Methodology

A	Q1 2020 QRAM Reference Price (Actual)	$ 144.88
	Q2 2020 QRAM Reference Price (Actual)	$ 131.75
	Q3 2020 QRAM Reference Price (Budget)	$ 153.33
	Q4 2020 QRAM Reference Price (Budget)	$ 153.33
B	Total annual LUF (Volume)	23,763

		Q1			Q2			Q3			Q4			
	2020 Budget	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
C	Fuel Profile - Based on 2020 Actuals for Jan-April, 2019 Actuals for May-Dec	7.34%	7.61%	7.90%	5.00%	6.82%	8.64%	10.12%	16.41%	17.23%	10.88%	0.39%	1.64%	100.00%
D = B*C	LUF Profile based on Fuel Profile (103m3)	1,745	1,809	1,878	1,189	1,620	2,054	2,405	3,900	4,094	2,587	93	391	23,763
E	% Fuel Allocation to Unreg Based on Activity - Based on actual activity for Jan-Apr, 2019 Actual Activity for May-Dec (Note 1)	0.44%	28.05%	20.92%	30.34%	21.67%	5.89%	14.66%	15.75%	3.19%	32.15%	0.30%	0.24%	
F = D*E	Unreg LUF Allocation (103m3)	7.75	507.29	392.94	360.75	350.95	120.98	352.60	614.30	130.45	831.58	0.28	0.94	3,670.81
G = A*F	**Annual $**	**1,123**	**73,496**	**56,929**	**47,531**	**46,239**	**15,940**	**54,066**	**94,192**	**20,002**	**127,509**	**43**	**144**	**537,215**

Note 1 The percentage allocators are calculated using gross monthly activity data.
Jan - Apr: The allocators are calculated using 2020 actual data.
May - Dec: 2019 Gross Storage Activity is used as a representation for 2020 Gross Storage Activity

Allocation for 2020 Under Existing Methodology

		Q1			Q2			Q3			Q4			
	2020 Budget	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
H	Unregulated LUF Allocation (103m3) - Note 2	283	283	283	283	283	283	283	283	283	283	283	283	2,838
I = A*H	**Annual $**	**41,028**	**41,028**	**41,028**	**37,311**	**37,311**	**37,311**	**43,422**	**43,422**	**43,422**	**43,422**	**43,422**	**43,422**	**495,544**

Note 2 Under the existing methodology, 14.3% of the total LUF provision for storage (0.12 bcf) is designated as being related to the unregulated storage operations, based on volumetric drivers for storage capacity measured in 2015.

Expected Impact for 2020 (+/- to unregulated business)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
C-E	**Impact for 2020**	**- 39,905**	**32,468**	**15,901**	**10,220**	**8,929**	**- 21,371**	**10,645**	**50,771**	**- 23,419**	**84,088**	**- 43,378**	**- 43,277**	**41,671**

Determining 2020 Impact
O&M: Storage
Legacy EGD and UG

Data Sources:
2020 O&M Budget (EGD and UG)
2018 O&M Storage Asset Information

Allocation for 2020 Under Harmonized Methodology

				EGD		UG		
O&M Classifcation	**O&M Sub-Classifcation**	**Allocator Description**	**Allocator**	**EGD 2020 Budget**	**EGD Unregulated O&M**	**UG 2020 Budget**	**UG Unregulated O&M**	
Storage General	Wells	Asset-based unregulated allocator for wells	48.59%	$ -	$ -	$ 264,090	$ 128,311	
	Lines	Asset-based unregulated allocator for lines	35.31%	$ -	$ -	$ 45,739	$ 16,152	
	Compressors	Asset based unregulated allocator for compressors	34.98%	$ 3,864,999	$ 1,352,002	$ 817,030	$ 285,803	
	Measuring and Regulating (M&R)	Asset based unregulated allocator for M&R	47.07%	$ 492,213	$ 231,660	$ 215,065	$ 101,221	
	Rents and Others	Weighted-average allocator for unregulated storage	30.32%	$ 3,453,943	$ 1,047,353	$ 1,900,478	$ 576,290	
Storage Shared	Compressors	Asset-based unregulated allocator for compressors	29.85%	$ -	$ -	$ 4,641,041	$ 1,385,556	
	Measuring and Regulating (M&R)	Regulatory cost study – M&RRECL-PT	40.82%		$ -	$ 44,045	$ 17,979	
	Dehydration	Regulatory cost study – Dehydration demand	64.70%	$ -	$ -	$ 180,907	$ 117,054	
	Supervision and Others	Regulatory cost study – O&M STO Split	9.41%	$ -	$ -	$ 12,439,149	$ 1,170,875	
Total					**$ 2,631,015** a		**$ 3,799,239**	b

Total EGI Unregulated O&M	**$ 6,430,254**	AA

Allocation for 2020 Under Existing Methodology

Unregulated Storage O&M Allocations - Based on 2020 Budget		
Legacy EGD - allocated O&M, property tax and labour markup	$ 2,382,750	
Calculated labour markup (per **O&M2**)	$ 471,494	
Caluclated property tax (per **PT - Storage**)	$ 283,297	
Adjusted legacy EGD unregulated storage O&M	**$ 1,627,959**	c
Legacy UG - Excluding Storage Support (Admin and Variable)	$ 3,922,812	d
Total Unregulated Storage O&M	**$ 5,550,770**	BB

Expected Impact for 2020 (+/- to unregulated business)

Impact for EGD	$ 1,003,057	
Impact for UG	-$ 123,573	
Impact for 2020	**$ 879,484**	AA-BB

Determining 2020 Impact
O&M: Storage Support - Admin and General
Legacy EGD and UG

Data Sources:
2020 O&M Budget (EGD and UG)
2018 O&M Storage Actuals (Regulated and Unregulated)
2019 and 2020 Cost Allocation Models (EGD)

Allocation for 2020 Under Harmonized Methodology

		Based on Actuals as at December 31, 2018
A	UG Unregulated Storage O&M costs	13,451,431
A	EGD Unregulated Storage O&M costs	2,627,515
B	UG Unregulated Storage Support Normalization	6,057,834
B	EGD Unregulated Storage Support Normalization - Note 1	104,437
C = (Sum of A) - (Sum of B)	EGI Adjusted Unregulated Storage O&M costs	9,916,675
D	UG Regulated Net O&M costs	448,420,938
D	EGD Regulated Net O&M costs	465,453,723
E	UG Regulated Storage Support Normalization	205,676,758
E	EGD Regulated Storage Support Normalization - Note 2	192,766,405
F = C + (Sum of D) - (Sum of E)	Total EGI Net O&M for the Core Business	525,348,173
G = C / F	**O&M Storage Support Allocator**	**1.89%**

		Based on 2020 Budget
H	2020 UG Budget for Storage Support IOs	200,111,295
I	2020 EGD Budget for Storage Support	189,534,352
Sum of H and I	**Total Storage Support**	**389,645,647**
H*G	UG Unregulated Storage O&M costs	3,777,378
I*G	EGD Unregulated Storage O&M costs	3,577,724
J = G * (Sum of H and I)	**Unregulated Storage Support O&M**	**7,355,102**

Note 1: Storage support represents the unregulated portion of the 65-70% markup on storage labour for 2018.
Note 2: Regulated storage support costs at legacy EGD are estimated by applying the proportion of total 2020 budget storage support costs and total 2020 budget O&M EGD expenses to the 2018 EGD Regulated Net O&M costs.

Legacy UG: Allocation for 2020 Under Existing Methodology

		Based on Actuals as at December 31, 2018
K	UG Unregulated storage O&M costs	13,451,431
L	UG Regulated storage O&M costs	448,420,938
M = K + L	UG Total Net O&M costs for the company	461,872,369
N = K / M	**O&M Storage Support Allocator**	**2.91%**

		Based on 2020 Budget
H	2020 UG Budget for Storage Support IOs	200,111,295
O = N * H	**UG Unregulated Storage Support Allocation Based on 2020 Budget**	**5,827,981**

Legacy EGD: Allocation for 2020 Under Existing Methodology

	AA	BB	CC = AA * BB	
	Fixed Allocator	**Unregulated Variable Allocator**	**Unregulated Allocator**	
Commodity - **Note 3**	5.00%	18.72%	0.94%	
Capacity - **Note 3**	73.00%	14.29%	10.43%	
Deliverability - **Note 3**	22.00%	17.20%	3.78%	
			15.15%	aa

		Based on 2020 Budget
P	Total Storage Labour Budget	4,644,948
Q	Average Labour Mark-Up % - **Note 4**	67%
R = P*Q	**Storage Support Labour Mark-Up (Prior to Allocation to Unreg)**	**3,112,115**

	Unregulated Storage Support Allocation:	**Based on 2020 Budget**
	Commodity	29,129
	Capacity	324,602
	Deliverability	117,762
S = aa * R	**Total Unregulated Storage Support Allocation Related to Mark Up**	**471,494**

Note 3: The fixed and varriable allocators used in this calculation are an an average of the respective allocators across all storage cost centres at legacy EGD, over 12 months.
Note 4: The average mark-up applied to labour is 67% across the different cost centres at legacy EGD.

Expected Impact for 2020 (+/- to unregulated business)

	EGD	**UG**	**EGI**
Harmonized method	3,577,724	3,777,378	7,355,102
Legacy method	471,494	5,827,981	6,299,475
Impact for 2020	**3,106,229**	- **2,050,603**	**1,055,627**

Determining 2020 Impact
O&M: Storage Support - Variable
Legacy UG and Legacy EGD

Data Sources:
2020 O&M Budget
Activity templates completed for 2021

Allocation for 2020 Under Harmonized Methodology

Activities Template Rates

		EGD					UG				EGI
Group	**Department**	**Cost Centre**	**Task**	**O&M Unreg Rate**	**2020 Budget (Net)**	**2020 Unreg O&M**	**IO**	**O&M Unreg Rate**	**2020 Budget (Net)**	**2020 Unreg O&M**	
Regulatory	Regulatory Applications & Strategy	CC25240	No Task	10%	$ 3,701,455	$ 370,145	IO312652	10%	$ 1,265,635	$ 126,563.45	
System Improvement	Lands, Permitting and Environment	N/A	N/A	N/A	N/A	$ -	IO340051	22%	$ 39,266	$ 8,638.50	
							IO340052	22%	$ 4,943	$ 1,087.48	
							IO340055	22%	$ 87,602	$ 19,272.51	
							IO340056	22%	$ 11,415	$ 2,511.38	
							IO340059	22%	$ 55,540	$ 12,218.78	
							IO340060	22%	$ 18,861	$ 4,149.47	
							IO340061	22%	$ 69,613	$ 15,314.95	
							IO340062	22%	$ 56,288	$ 12,383.26	
							IO340064	22%	$ 74,433	$ 16,375.20	
							IO340065	22%	$ 75,395	$ 16,586.98	
							IO340066	22%	$ 37,763	$ 8,307.95	
							IO340067	22%	$ 72,690	$ 15,991.90	
							IO340068	22%	$ 49,595	$ 10,910.87	
							IO340100	22%	$ 74,034	$ 16,287.47	
							IO340101	22%	$ 243,401	$ 53,548.15	
							IO340104	22%	$ 122,878	$ 27,033.24	
							IO340200	22%	$ 34,605	$ 7,613.12	
							IO340201	22%	$ 10,040	$ 2,208.81	
							IO340220	22%	$ 53,947	$ 11,868.29	
							IO340221	22%	$ 71,096	$ 15,641.13	
							IO340300	22%	$ 54,367	$ 11,960.72	
							IO341200	22%	$ 55,660	$ 12,245.20	
							IO341900	46%	$ 58,592	$ 26,952.26	
							IO342400	46%	$ 22,534	$ 10,365.86	
							IO343001	46%	$ 98,504	$ 45,311.75	
							IO343160	22%	$ 229,647	$ 50,522.25	
							IO343161	22%	$ 109,503	$ 24,090.62	
							IO343162	22%	$ 2,000	$ 440.06	
Storage and Transmission	S&T Business Development	N/A	N/A	N/A	N/A	$ -	IO240892	20%	$ 547,838	$ 109,567.63	
Storage and Transmission	Underground Storage and Reservoir Engineering	CC25124	T_65040	35%	$ 123,993	$ 43,397	IO340037	35%	$ 1,718,798	$ 601,579.19	
Asset Management	Storage Asset Management	CC25161	T161G	40%	$ 51,382	$ 20,553	IO342675	40%	$ 182,773	$ 73,109.09	
A **Total**						**$ 434,096**				**$ 1,370,657.51**	**$ 1,804,753.32**
Total EGI											

Allocation for 2020 Under Existing Methodology

	EGD	UG	EGI
B **Total**	**$ -**	**$ 1,370,657.51**	**$ 1,370,657.51**

Expected Impact for 2020 (+/- to unregulated business)

	EGD	UG	EGI
C **Impact for 2020**	**$ 434,095.81**	**$ -**	**$ 434,095.81**

Determining 2020 Impact
Depreciation Expense - General Plant Assets
Legacy UG and Legacy EGD

Data Sources:
2020 Capital Asset Forecast

Data Sources for General Plant Allocators:
2018 O&M data from the O&M team (SAP and Oracle)
2020 Capital Asset Forecast
2020 O&M Budget

Depreciation Expense for General Plant Assets: Calculating Allocation for 2020 Under Harmonized Methodology

		EGD	UG
	2020 General Plant Assets (based on 2+10 forecast) - Depreciation Expense	67,461,357	43,941,280
	Adjustments for EGD:		
	IT Software (CIS acquired software, software acquired intangibles, software developed intangibles, WAMS)	48,660,375	-
	Administrative buildings and accompanying land		
	Markham TOC	726,880	-
	Ottawa	516,464	-
	Thorold	535,090	-
	VPC	5,541,805	-
A	2020 General Plant Assets (based on 2+10 forecast) - Depreciation expense adjusted for unreg allocation purposes	123,441,971	43,941,280
B	General Plant Allocation Factor	0.94%	3.03%
C = A*B	**2020 Unreg Depreciation Expense related to General Plant Assets**	**1,160,007**	**1,333,183**

Depreciation Expense for General Plant Assets: Allocation for 2020 Under Existing Methodology

		EGD	UG
D	**2020 Unreg Depreciation Expense (based on 2+10 forecast) - General Plant Assets**	**-**	**1,326,355**

Depreciation Expense for General Plant Assets: Expected Impact for 2020 (+/- to unregulated business)

		EGD	UG
E = C-D	**Impact for 2020**	**1,160,007**	**6,829**

Determining 2020 Impact
Property Tax - Storage Assets
Legacy UG and Legacy EGD

Data Sources:
2018 Capital Asset PPE Schedule (Schedule 5)
2020 Property Tax Budget
2020 EGD storage allocation model for Jan-Mar

Calculating Allocation for 2020 Under Harmonized Methodology

	EGD			UG		
	A	B	C = A/B	AA	BB	CC = AA/BB
Storage Property tax	**2018 Unreg Storage Assets**	**2018 Total Storage Assets for Tecumseh**	**2018 Unreg Percentages**	**2018 Unreg Storage Assets**	**2018 Total Storage Assets**	**2018 Unreg Percentages**
Mains (Pipelines)	29,794,165	132,107,655	22.55%	51,539,012	97,918,504	52.63%
Well (including well equipment)	14,772,476	84,025,779	17.58%	95,168,027	142,044,272	67.00%
Land	1,127,303	5,923,679	19.03%	2,244,659	7,765,501	28.91%
Buildings	286,182	31,561,989	0.91%	25,723,513	94,654,198	27.18%
Compressors	22,736,252	158,622,313	14.33%	162,201,324	627,802,304	25.84%
	68,716,379	412,241,414	16.67%	336,876,534	970,184,779	34.72%

		D	DD	EE	FF = DD*EE
Note 1	**Storage Property tax**	**Expected 2020 Tecumseh Property**	**2019 Property Tax**	**Inflation**	**Expected 2020 Property Taxes**
	Mains (Pipelines)	812,691	1,093,578	1.25%	1,107,248
	Well	70,668	157,240	1.25%	159,206
	Land	35,334	172,597	1.25%	174,754
	Buildings	212,006	344,953	1.25%	349,265
	Compressors	636,019	2,312,869	1.25%	2,341,780
		1,766,718 a	4,081,237		4,132,252

	E = C*D	GG = CC * FF
Unregulated Storage Property Tax	**Expected 2020 Property Taxes Allocated to Unreg**	**Expected 2020 Property Taxes Allocated to Unreg**
Mains (Pipelines)	183,286	582,795
Well	12,424	106,666
Land	6,724	50,514
Buildings	1,922	94,917
Compressors	91,164	605,031
Total Unregulated Storage Property Tax	**295,521**	**1,439,923** aa

Note 1: For EGD: Only storage property tax that are shared between regulated and unregulated activites (to be allocated) are included here. This does not include storage property taxes that can be directly attributed to the unregulated storage operations and booked in the unregulated LOB (CC25371), or storage operations related to Crowland (100% regulated).

Allocation for 2020 Under Existing Methodology

		EGD			UG
For Legacy EGD:	F	G	H = F*G		
Split of Balance:	**Fixed Allocator**	**Unregulated Variable Allocator**	**Unregulated Allocator**		
Capacity	40%	14.29%	6%		
Deliverability	60%	17.20%	10%		
Expected 2020 Property Tax		a	1,766,718		
Unregulated Property Tax:					
Capacity			100,972		
Deliverability			182,325		
Total Unregulated Property Tax		a*H	**283,297**	b	
					Expected 2020 Property Taxes
For Legacy UG:					
Total Unregulated Property Tax				aa	**1,439,923** bb

Expected Impact for 2020 (+/- to unregulated business)

Impact for 2020	a-b	**12,223**	aa-bb	-

Determining 2020 Impact
Property Tax - General Plant Assets
Legacy UG and Legacy EGD

Data Sources:
2020 Property Tax Budget
2018 Capital Asset PPE Schedule (Schedule 5)

Data Sources for General Plant Allocators:
2018 O&M data from the O&M team (SAP and Oracle)
2020 Capital Asset Forecast
2020 O&M Budget

Calculating Allocation for 2020 Under Harmonized Methodology

	EGD			UG				
	A	B	C = A*B	AA	BB	CC = AA*BB	DD	EE = CC*DD
	Estimated 2020 Taxes	General Plant Allocator	Taxes attributed to Unreg Storage	2019 Property Tax	Inflation	Expected 2020 Property Taxes	General Plant Allocator	Taxes attributed to Unreg Storage
General Plant Assets subject to Property Tax				724,573	1.25%	733,630	3%	22,258.43
Markham - TOC	273,865	0.94%	2,573.56					
Ottawa - Conventry Rd	218,890	0.94%	2,056.95					
Thorold - Schmon Pkwy	152,651	0.94%	1,434.49					
North York - VPC	843,847	0.94%	7,929.79					
Total	1,489,253		**13,994.80**			733,630.45		**22,258.43**

Allocation for 2020 Under Existing Methodology

	A	D	E = A*D	AA	BB	CC = AA*BB	FF	GG = CC*FF
	Estimated 2020 Taxes	General Plant Allocator	Taxes attributed to Unreg Storage	2019 Property Tax	Inflation	Expected 2020 Property Taxes	General Plant Allocator	Taxes attributed to Unreg Storage
Taxes	1,489,253	0%	-	724,573	1.25%	733,630	3.64%	**26,727.57**

Expected Impact for 2020 (+/- to unregulated business)

	EGD: Taxes attributed to Unreg Storage	UG: Taxes attributed to Unreg Storage
Impact for 2020	**13,994.80**	**- 4,469.14**

2024 Unregulated Storage Cost Allocation Calculation From Harmonized Methodology

Line No.	Particulars ($ millions)	2024 Harmonized Methodology	Relevant Tab
		(a)	(b)
	Unregulated Storage Asset Balances		
1	Materials and Supplies Inventory	2.1	Unreg Materials & Supplies
2	Net Underground Storage Plant	436.8	N/A - Allocation is Determined On a One Time Basis
3	Net General Plant	10.4	Unreg Net General Plant
4	Total Net Unregulated Storage Assets	449.3	
	Unregulated Storage Operating Expenses		
5	Cost of Gas: Unaccounted For Gas	5.3	Unreg UFG
6	Cost of Gas: Fuel Used to Move Gas	2.9	Unreg Fuel
7	O&M: Storage Operations	0.0	Unreg O&M Storage Operations
8	O&M: Storage Support – Administrative and General	0.0	Unreg O&M Storage Support - A&G
9	O&M: Storage Support – Variable	0.0	Unreg O&M Storage Support - Var
10	Depreciation Expense: Storage Assets	19.3	N/A - Supporting Calculation Maintained In Depreciation Model
11	Depreciation Expense: General Plant Assets	1.3	Unreg General Plant Depr
12	Property Tax Expense: Storage Assets	0.0	Unreg Property Tax
13	Property Tax Expense: General Plant Assets	0.0	Unreg Property Tax
14	Unutilized In-franchise Space	-	
15	Interest Expense on Long Term Debt	12.3	Interest Expense
16	Total Unregulated Storage Operating Expenses	41.0	

Enbridge Gas Inc. Allocation of Materials & Supplies Inventory for 2024

Line No.	Particulars ($ millions)	EGD	Union	Total Enbridge Gas Inc.
		(a)	(b)	(c)
1	January 1	65.0	39.5	104.5
2	January 31	66.0	38.1	104.1
3	February	66.3	38.2	104.6
4	March	67.3	38.8	106.1
5	April	68.9	39.7	108.7
6	May	69.1	39.9	109.0
7	June	70.0	40.4	110.4
8	July	71.1	41.0	112.1
9	August	72.8	42.0	114.8
10	September	69.4	40.0	109.4
11	October	70.5	40.7	111.2
12	November	71.7	41.3	113.0
13	December	68.4	39.5	107.9
14	Average of Averages	69.2	40.0	109.1
15	General Plant Allocation Factor (1)			1.91%
16	Allocated to Unregulated Storage			2.1

Note:
(1) See relevant tab for calculation.

Enbridge Gas Inc. Allocation of General Plant Assets for 2024

Line No.	Particulars ($ millions)	Union	EGD	Total
		(a)	(b)	(c)
1	Gross General Plant - December 31, 2023	343.6	318.7	662.3
2	Legacy General Plant - Regulated	331.1	318.7	649.8
3	Legacy Allocation to Union Unregulated Storage	12.5	0.0	12.5
4	Transfer to General Plant on Harmonization - EGD Buildings	0.0	140.4	140.4
5	Adjusted General Plant - January 1, 2024	343.6	459.1	802.7
6	Additions to General Plant - 2024	11.8	49.7	61.5
7	Retirements of General Plant - 2024	(15.0)	(12.8)	(27.8)
8	Gross General Plant to be Allocated	340.4	496.0	836.4
9	Allocated to Unregulated Storage on Harmonization	12.5	8.9	21.3
10	General Plant Allocation Factor on additions	1.91%	1.91%	1.91%
11	Allocated to Unregulated Storage in 2024	(0.1)	0.8	0.7
12	Accumulated Depreciation General Plant - December 31, 2023	155.9	186.5	342.3
13	Legacy General Plant - Regulated	149.8	186.5	336.3
14	Legacy Allocation to Union Unregulated Storage	6.0	0.0	6.0
15	Transfer to General Plant on Harmonization - EGD Buildings	0.0	52.1	52.1
16	Adjusted General Plant - January 1, 2024	155.9	238.5	394.4
17	Depreciation General Plant - 2024	25.4	32.9	58.3
18	Retirements of General Plant - 2024	(15.0)	(12.8)	(27.8)
19	Accumulated Depreciation General Plant to be Allocated	166.3	258.6	424.9
20	Allocated to Unregulated Storage on Harmonization	6.0	4.9	11.0
21	General Plant Allocation Factor	1.91%	1.91%	1.91%
22	Allocated to Unregulated Storage in 2024	0.4	0.3	0.7
23	Net Allocation to Unregulated Storage	6.0	4.4	10.4

Unregulated Storage Cost Allocation - 2024 Unaccounted For Gas (UFG)

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Gross Monthly Activity of Unregulated Storage (PJ)	75.2	61.3	33.9	40.7	39.4	31.0	30.0	31.1	18.6	21.1	14.8	58.0	455.2
2	Gross Monthly Activity of Total Storage and Transportation (PJ)	513.4	431.0	407.8	338.9	318.9	292.1	314.7	307.8	269.0	287.5	300.7	486.8	4268.7
3	Forecast Allocators (%) (line 1 / line 2) (1)	14.6%	14.2%	8.3%	12.0%	12.4%	10.6%	9.5%	10.1%	6.9%	7.3%	4.9%	11.9%	
4	Forecasted Total UFG Cost ($ millions) (2)	8.3	7.7	7.3	5.3	3.5	2.5	2.6	2.4	2.3	3.0	5.0	6.7	56.6
5	Forecasted Unregulated UFG Cost ($ millions) (line 3 * line 4)	1.2	1.1	0.6	0.6	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.8	6.2
6	Unregulated Amount Recovered From Customer Supplied Fuel for UFG ($ millions)													0.8
7	Forecasted Cost Gas: Unanccounted For Gas ($ millions) (line 5 - line 6)													5.3

Notes:
(1) Forecasted allocator is based on 2022 actual activity.
(2) Settlement Update as per EB-2022-0200, Exhibit O1, Tab 1, Schedule 1.

Unregulated Storage Cost Allocation - 2024 Fuel Used to Move Gas

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Net Daily Activity of Unregulated Storage (10^3m^3)	3,695	3,711	1,280	397	599	1,526	874	1,544	2,106	1,643	651	595	18,622
2	Net Daily Activity of Total Storage (10^3m^3)	5,409	7,748	4,745	772	1,142	4,662	4,525	6,270	6,116	3,488	1,670	1,792	48,340
3	Forecast Allocators (%) (line 1 / line 2) (1)	68.3%	47.9%	27.0%	51.4%	52.5%	32.7%	19.3%	24.6%	34.4%	47.1%	39.0%	33.2%	
4	Forecasted Total Fuel Cost ($ millions)	1.1	1.1	1.2	1.1	0.7	0.5	0.7	1.4	1.6	1.6	0.4	0.1	11.5
5	Forecasted Unregulated Fuel Cost ($ millions) (line 3 * line 4)	0.8	0.5	0.3	0.5	0.4	0.2	0.1	0.3	0.5	0.8	0.1	0.0	4.7
6	Unregulated Amount Recovered From Customer Supplied Fuel for Fuel ($ millions)													2.0
7	Forecasted Cost of Gas: Fuel Used to Move Gas ($ millions) (line 5 - line 6)													2.6
8	Forecasted Cost of Gas: Company Use ($ millions) (2)													0.2
9	Forecasted Cost of Gas: Fuel Used to Move Gas and Company Use ($ millions) (3)													2.9

Notes:
(1) Forecasted allocator is based on 2022 actual activity.
(2) Please see Phase 2 Exhibit 4, Tab 2, Schedule 1, Attachment 1, page 4, line 18.
(3) Phase 2 Exhibit 1, Tab 13, Schedule 2, Table 2 , Line 6 includes unregulated forecasted cost of gas for own use.

Determining Enbridge Gas Inc. Allocation For 2024 Storage Operations
Allocation for 2024 Under Harmonized Methodology

					Enbridge Gas Inc.	
Line No.	O&M Classifcation	O&M Sub-Classifcation	Allocator Description	Allocator	2024 Budget ($ millions)	Unregulated O&M ($ millions)
	(a)	(b)	(c)	(d)	(e)	(f)
1	Storage General	Wells	Asset-based unregulated allocator for wells	49.48%	0.0	0.0
2		Lines	Asset-based unregulated allocator for lines	33.27%	0.8	0.3
3		Compressors	Asset based unregulated allocator for compressors	23.31%	3.3	0.8
4		Measuring and Regulating (M&R)	Asset based unregulated allocator for M&R	40.93%	0.0	0.0
5		75% compressor, 25% M&R	Asset based unregulated allocator for M&R and comp	24.10%	3.3	0.8
6		Rents and Others	Weighted-average allocator for unregulated storage	30.87%	8.3	2.6
7	Storage Shared	Compressors	Asset-based unregulated allocator for compressors	23.31%	5.4	1.3
8		Supervision and Others	Regulatory cost study – O&M STO Split	10.00%	22.0	2.2
9	Total EGI Unregulated O&M					7.8
					Rate Order Adjustment	(0.2)
						7.6

Determining Enbridge Gas Inc. Allocation For 2024 Storage Support - Admin and General
Allocation for 2024 Under Harmonized Methodology

Line No.	Particulars ($ millions)	Based on Actuals as at December 31, 2022
1	EGI Unregulated Storage O&M Costs	19.1
2	EGI Unregulated Storage Support O&M Costs	(8.5)
3	EGI Adjusted Unregulated Storage O&M Costs (line 1 + line 2)	10.6
4	EGI Regulated Net O&M costs	1,002.6
5	EGI Regulated Net O&M Support Costs	(477.0)
6	Total EGI Net O&M for the Core Business (line 3 + line 4 + line 5)	536.1
7	O&M Storage Support Allocator (line 3 / line 6)	1.97%
		Based on 2024 Budget
8	Total 2024 EGI Budget for Storage Support	337.9
9	EGI Unregulated Storage O&M Costs (Allocated) (line 8 * line 7)	6.7
10	EGI Unregulated Storage O&M Costs (Direct)	0.2
11	Total EGI Unregulated Storage O&M Costs	6.9
12	Rate Order Adjustment	0.5
13		7.4

Determining Enbridge Gas Inc. Allocation For 2024 Storage Support - Variable

Allocation for 2024 Under Harmonized Methodology

Activities Template Rates

Line No.	Group	Department	Cost Centre / Internal Order	Task	O&M Unreg Rate	2024 Budget (Net) ($ 000s)	2024 Unreg O&M ($ 000s)
			(a)	(b)	(c)	(d)	(e)
1	Regulatory	Regulatory Applications & Strategy	CC25240 / IO312652	N/A	10%	$ 5,487.9	$ 548.8
2	System Improvement	Lands, Permitting and Environment	IO240892	N/A	20%	$ 461.0	$ 92.2
3			IO340037	N/A	35%	$ 1,250.9	$ 437.8
4			IO342675	N/A	40%	$ 88.5	$ 35.4
	Storage and Transmission	Underground Storage and Reservoir Engineering	CC25124	T_65040	35%		$ 187.1
5						$ 534.7	
6	Asset Management	Storage Asset Management	CC25161	T161G	40%	$ 3.7	$ 1.5
7	Total						$ 1,302.8
8						Rate Order Adjustment	$ (13.55)
9							$ 1,289

Determining Enbridge Gas Inc. Allocation For 2024 General Plant Assets - Depreciation
Allocation for 2024 Under Harmonized Methodology

Line No.	Particulars ($ millions)	
1	Total 2024 Depreciation Expense - General Plant Assets	58.8
2	General Plant Allocation Factor (See Relevant Tab For Calculation)	1.91%
3	Total EGI Unregulated Depreciation Expense for General Plant Assets	1.3

Determining Enbridge Gas Inc. Allocation For 2024 Property Taxes

STORAGE ASSETS - Calculating Property Tax Allocator for 2024 Property Taxes

	Enbridge Gas Distribution				Union Gas		
	(a)	(b)	(c) = (a) + (b)	(d) = (a) / (c)	(g)	(h)	(i) = (g)/(h)
Storage Property tax ($ millions)	2022 Unreg Storage Assets (Tecumseh)	2022 Regulated Storage Assets (Tecumseh)	Total Storage Assets (Tecumseh)	2022 Unreg Percentages (to be applied to Tecumseh taxes)	2022 Unreg Storage Assets	2022 Total Storage Assets	2022 Unreg Percentages (to be applied to Storage taxes)
Mains (Pipelines)	31.5	115.3	146.7	21.45%	78.4	132.7	59.08%
Well (Including well equipment)	17.5	69.4	86.8	20.14%	100.5	149.7	67.12%
Land	6.8	5.3	12.1	56.01%	3.0	14.1	21.51%
Buildings	0.4	61.4	61.8	0.66%	26.3	97.1	27.09%
Compressors	24.2	179.6	203.8	11.88%	176.5	655.5	26.92%
Total	80.3	430.8	511.2	15.72%	384.7	1,049.1	36.67%

STORAGE ASSETS - Calculating Property Tax Allocation for 2024 Property Taxes

	(e)	(f) = (d)*(e)	(j)	(k) = (i)*(j)
Storage Property Tax ($ millions)	Expected 2024 Property Taxes Paid on Tecumseh	Annual Unregulated Accrual	Expected 2024 Property Taxes Paid on Storage	Annual Unregulated Accrual
Mains (Pipelines)	1.5	0.3	1.1	0.6
Well (Including well equipment)	0.1	0.0	0.2	0.1
Land	0.0	0.0	0.2	0.0
Buildings	0.2	0.0	0.3	0.1
Compressors	0.5	0.1	2.3	0.6
Total	2.3	0.4	4.1	1.5

GENERAL PLANT ASSETS - Calculating Property Tax Allocation for 2024 Property Taxes

Property Tax ($ millions)	Expected 2024 Property Taxes Paid for General Plant Assets	Expected 2024 Property Taxes Paid for General Plant Assets
General Plant Assets subject to Property Tax		0.7
Markham - TOC	0.3	
Ottawa - Conventry Rd	0.2	
North York - VPC	0.9	
Total	1.4	0.7
General Plant Allocation Factor (See Relevant Tab For Calculation)	1.91%	1.91%
Annual Unregulated Accrual	0.0262	0.0141

Determining Enbridge Gas Inc. Allocation
For 2024 Interest Expense on Long Term Debt

Line No.	Particulars ($ millions)		Average of Monthly Averages	Carrying Cost
			(a)	(b)
	Long and Medium-Term Debt			
1	Debt Summary		10,415.7	430.3
2	Unamortized Finance Costs		(91.5)	0.0
3	(Profit)/Loss on Redemption		0.0	0.0
4			10,324.2	430.3
5	Percentage Allocation of Debt to Unregulated	2.87%	296.1	12.3

Calculation of 2024 General Plant Allocation Factor
(Based on December 31, 2022 Actuals)

Line No.	Particulars ($ millions)	EGD	Union	Total Enbridge Gas Inc.
		(a)	(b)	(c)
1	Total Gross Plant (excluding WIP, general plant and other unregulated activities)	11,197.1	11,745.9	22,943.0
2	Total Unregulated Gross Storage Plant	106.3	476.1	582.4
3	% Unregulated Storage to Total Plant	0.95%	4.05%	2.54%
4	Total Unregulated Storage O&M Costs			13.1
5	Total Net O&M costs (excluding other unregulated activities)			1,025.6
6	O&M Storage Support Allocator			1.28%
7	General Plant Allocation Factor			1.91%

DAWN TO CORUNNA REPLACEMENT PROJECT

JASON GILLETT, DIRECTOR S&T BUSINESS DEVELOPMENT AND SALES
STEVEN PARDY, MANAGER UNDERGROUND STORAGE & TRANSMISSION PLANNING
MATT THOMAS, MANAGER S&T BUSINESS DEVELOPMENT
EHI UWAGBOE, MANAGER PROJECTS

1. Enbridge Gas has provided this evidence to reflect the following issues that are being addressed in Phase 2 of this Application.

    6) Is the 2024 proposed rate base appropriate?

    50) Is the allocation of capital assets and costs between utility and non-utility (unregulated) storage operations appropriate?

2. The purpose of this evidence is to demonstrate that the Dawn to Corunna Replacement Project[1] (the Project) costs are reasonable and prudent and request approval that 100 percent of the costs be included in 2024 regulated rate base. The amount to be included in 2024 rate base is $338.8 million.

3. This evidence will address the integration of the storage systems related to the amalgamation of EGD and Union as required by the OEB's Decision and Order[2] which approved Leave-to-Construct for the Project.

[1] EB-2022-0086.
[2] EB-2022-0086, Decision and Order, November 2, 2022.

4. The Project does not create any incremental storage capacity, withdrawal capability or injection capability. By applying either the storage cost allocation methodology in place at the time of Project approval or the harmonized storage cost allocation methodology, the result is 100 percent of the project costs being allocated to regulated operations.

5. The integration of the EGD and Union storage networks after amalgamation did not provide any additional storage space, withdrawal capability or injection capability. The integration of the storage systems has provided Enbridge Gas with more flexibility to better manage outages required to complete construction and maintenance activities as it no longer required coordination by two separate utilities to manage these outages. Details of the integration of the EGD and Union storage systems have been provided at Attachment 1.

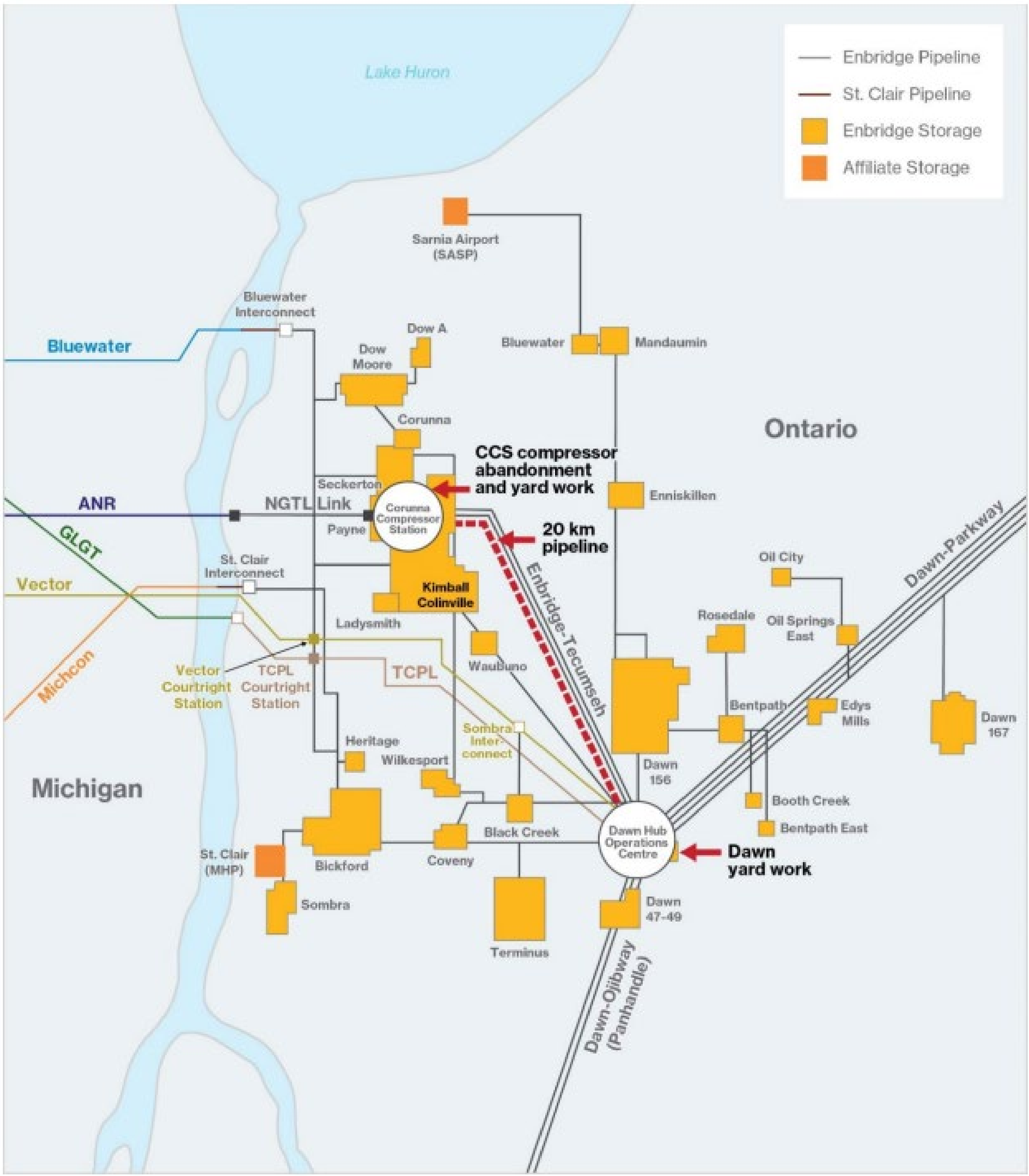
6. This evidence is organized as follows:
    1. Background – Dawn to Corunna Replacement Project
    2. Integration of the Storage Systems
    3. Cost Allocation
    4. Project Status and Cost Summary
    5. 2024 Rate Base – Dawn to Corunna Replacement Project
    6. Review of Alternatives

<u>1. Background – Dawn to Corunna Replacement Project</u>

7. The Project enabled the abandonment and retirement of seven compressor units at the Corunna Compressor Station (CCS) to address known obsolescence, reliability, and safety risks. The Project consisted of constructing approximately 20 km of NPS 36 natural gas pipeline between the CCS and the Dawn Operations Centre, as well as associated station work. The CCS and the Dawn Operations Centre are the two

main compression locations of the Dawn Hub. The Project maintains withdrawal and injection capability and working capacity at the Dawn Hub. A map of the Project and existing Dawn Storage Facilities is presented in Figure 1.

Figure 1: Enbridge Gas Inc. Dawn Hub and Storage Facilities



8. The Project received Leave-to-Construct approval on November 3, 2022. Construction activities for the Project commenced in March 2023. The Project was placed in-service November 30, 2023.

9. On page 2 of its Decision and Order[3] for the Project, the OEB noted that:

> The OEB also finds that Enbridge Gas did not seek to establish that the Project is for the benefit of ratepayers in the context of its integrated storage system and that the ability to include the proposed assets in rate base is a matter that Enbridge Gas may pursue in its 2024 rebasing proceeding.

Enbridge Gas interprets this to mean that Enbridge Gas needs to establish the portion of the Project costs that it intends to include as part of its regulated rate base in this 2024 Rebasing proceeding. This is supported by the following on page 9 of the Decision[4]:

> The rebasing proceeding will address the appropriate allocation of storage and storage related costs to each of the regulated business and the unregulated business and, if Enbridge Gas seeks to put the Project into rate base, the extent to which the recovery of the cost of the Project from ratepayers is appropriate.

2. Integration of the Storage Systems

10. The Dawn Hub is one of the largest and most important natural gas market hubs in North America and consists of a combination of interconnecting natural gas pipelines and underground storage facilities. Enbridge Gas operates storage and

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[3] EB-2022-0086, Decision and Order, November 3, 2022.
[4] Ibid.

transmission assets that include 322 PJ[5] of underground natural gas storage space at the Dawn Hub in an integrated system of assets.

11. On page 9 of its Decision and Order[6] for the Project, the OEB noted that:

> The OEB is of the view that the concerns raised by Pollution Probe and Energy Probe regarding the need for an examination of the overall integration of storage assets between the legacy storage of Enbridge Gas Distribution and Union Gas Limited is best addressed in the upcoming Enbridge Gas rebasing proceeding.

12. In response to the Dawn to Corunna Decision, Enbridge Gas prepared documentation provided at Attachment 1 to review the impacts resulting from the integrated operation of the EGD and Union storage systems. The integration of the EGD and Union storage systems did not create additional storage space or withdrawal and injection capability. The two systems were developed independently, were already connected at Dawn, and each company had maximized the capability of the existing facilities. The infrastructure and the limited number of connections in place prior to amalgamation were available to the integrated utility.

13. Prior to the amalgamation of EGD and Union, the EGD storage system was directly connected to the Dawn Hub by two NPS 30 pipelines[7] between the CCS and the Dawn Operations Centre. Additionally, a NPS 16 pipeline, commonly known as the TSLE pipeline, connects the Coveny, Black Creek and Wilkesport storage pools directly to Dawn. Natural gas supplies contracted to fill the EGD storage pools

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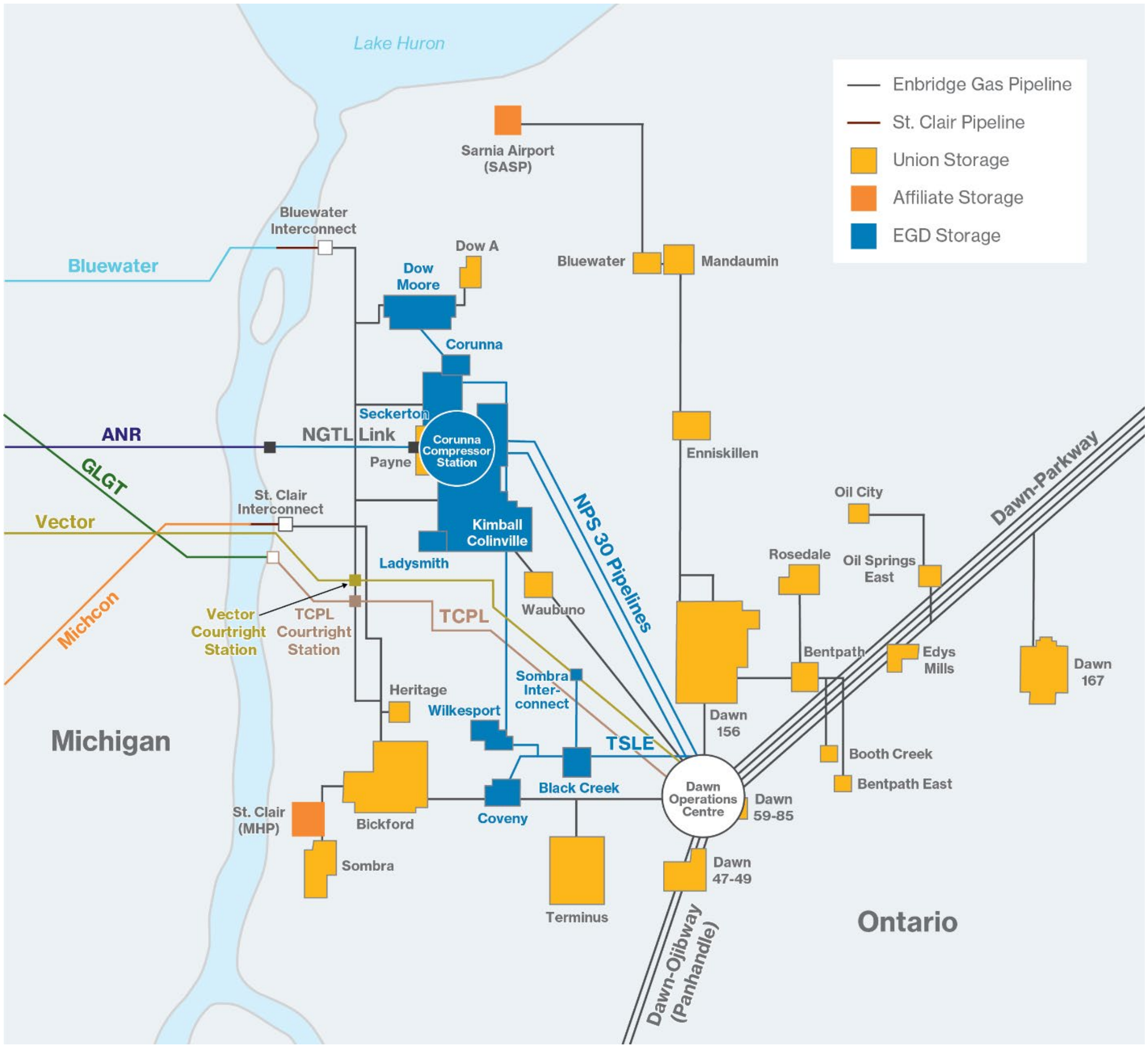
[5] Includes 7.9 PJ of storage capacity operated by Enbridge Gas and owned by Market Hub Partners Canada L.P. and Sarnia Airport Storage Pool L.P.
[6] EB-2022-0086, Decision and Order, November 3, 2022.
[7]Sometimes referred to as the twin 30's or TR1 and TR2

flowed through the Dawn Operations Centre. Natural gas withdrawn from the EGD storage pools flowed to the Dawn Operations Centre via the two NPS 30 pipelines and the TSLE pipeline. Figure 2 shows that all[8] the EGD storage pools flow through Dawn and rely on compression and dehydration facilities at Dawn to be transported on the Dawn Parkway System. All of these facilities existed prior to the amalgamation of Union and EGD.

[8] Except for the Crowland pool which is in the Niagara region and the Chatham D pool which is connected to the Panhandle system.

Figure 2: Interconnection of EGD Storage and the Dawn Operations Centre



14. EGD had contracts with Union to transport gas from the EGD storage system through Dawn into the Dawn Parkway System. Union's design day analysis included provisions for 1.9 PJ/d of gas from the EGD storage system (to be delivered to Dawn at 4,825 kPag). Therefore, the pipeline, compression, and

dehydration facilities at Dawn were designed and sized to serve both the Union and EGD storage systems. The integration of the two storage networks after amalgamation did not provide any ability to change the underlying assumptions that were used to design the facilities at Dawn. As a result, the integration of the storage networks did not create any additional capability. Incremental storage capacity, withdrawal capability and injection capability can only be created by constructing additional facilities.

15. To determine the amount of withdrawal capability available from the storage system, Enbridge Gas completes an annual design day analysis that models all storage facilities. This analysis incorporates annual updates to storage, pipeline and compressor parameters and any changes to existing facilities. Additionally, any new facilities are incorporated into the design day model. The purpose of this analysis is to determine the maximum amount of withdrawal capability available from the storage system.

16. Prior to amalgamation, EGD and Union had separately completed analysis on the withdrawal capability of their respective storage systems. Following amalgamation, Enbridge Gas initiated the development of a combined design day model to complete analysis to determine the withdrawal capability of the combined system. The results of this analysis confirmed that the integration of the two systems did not create any incremental capability as shown in Table 1. Further details regarding the development of the combined design day analysis are outlined in Attachment 1. This result was consistent with Enbridge Gas's understanding of the integrated storage system since the storage systems were already connected, the Union design day analysis already included flows from the EGD storage system, and no new assets were added.

Table 1
Comparison of Design Day Withdrawal Capability

Line No.	Particulars (TJ/d)	Separate Models	Combined Model	Difference
		(a)	(b)	(b) – (a)
1	Union	3,866	3,850	(16)
2	EGD	2,423	2,424	1
3	Totals	6,289	6,274	(15)

17. As stated in Enbridge Gas's Reply Argument as to whether it evaluated the integration opportunities of the CCS and Dawn storage system (forming part of the Dawn Hub)[9]:

> "However, Enbridge Gas analyzes its storage system on an integrated basis. The two storage systems are currently only connected at Dawn. The integrated system is primarily evaluated based on storage capacity and design day deliverability. **The integration of the systems does not have any impact on the storage capacity of the individual storage pools.** When evaluating design day deliverability, it is important to understand that the two storage systems were designed around similar design day principles to meet design day conditions. **In addition, the pipeline and compression facilities are, for the most part, fully utilized. Therefore, any opportunities would require the construction of new facilities or the modification of existing facilities."** (emphasis added)

18. In summary, after examining the impacts resulting from the integrated operation of the EGD and Union storage systems, the integration did not create additional storage space, withdrawal capability or injection capability.

[9] EB-2022-0086 Dawn to Corunna Replacement Project Reply Argument, pp.26-27

3. Cost Allocation

19. Evidence related to Enbridge Gas's proposed harmonized unregulated storage cost allocation methodology is set out at Phase 2 Exhibit 1, Tab 13, Schedule 2.

20. Evidence related to the amount of regulated cost-based storage space that is appropriate for in-franchise customers is set out at Phase 2 Exhibit 4, Tab 2, Schedule 8.

21. The seven compressor units that were retired and abandoned as part of the Project were constructed between 1964 and 1974 and were EGD assets prior to amalgamation. These compressors enabled part of the EGD storage capacity, injection and withdrawal capabilities in place at the time of the NGEIR Decision and were 100 percent allocated to regulated operations.

22. By applying either the storage cost allocation methodology in place at the time of Project approval or the harmonized storage cost allocation methodology, the result is 100 percent of the project costs being allocated to regulated operations because the Project is a replacement of assets allocated to regulated operations.

23. The seven compressor units provided mid-range compression for both injection and withdrawal modes. Retirement and abandonment of these units would have reduced EGD rate zone in-franchise storage capacity by 20.4 PJ (5.7 PJ due to reduced withdrawal capability and 14.7 PJ due to reduced injection capability), and the design day storage withdrawal capability would be reduced by 0.67 PJ/d.

24. Without alternatives to replace these units, Enbridge Gas would strand this storage space and would have been forced to purchase supply-side services to meet the

demands of its customers.

25. The Dawn to Corunna pipeline and associated station work at the CCS and the Dawn Operations Centre to connect the new pipeline to the existing facilities maintains withdrawal and injection capability and working capacity at the Dawn Hub.

26. Enbridge Gas confirmed in the Dawn to Corunna LTC proceeding[10] that the Project replaces the existing system capacity and does not provide ability for Enbridge Gas to offer new or expanded market-based services.

27. Prior to the amalgamation of EGD and Union, both utilities applied approved cost allocation[11,12,13,14,15] methodologies that assigned the costs of storage investments to its regulated and unregulated storage operations. The principles of these methodologies for both EGD and Union were similar in nature and have continued to be applied throughout the deferred rebasing period and are summarized in Table 2.

[10] EB-2022-0086, Exhibit I.Staff.9, part (d), June 30, 2022.
[11] EB-2011-0354, Exhibit D2, Tab 5, Schedule 1 – Black & Veatch Independent Review.
[12] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review.
[13] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review.
[14] EB-2011-0038, Decision and Order, January 20, 2012, and EB-2013-0365, Settlement Agreement, June 3, 2014.
[15] EB-2011-0354, Settlement Agreement, October 15, 2012, and EB-2015-0114, Decision and Interim Rate Order, December 10, 2015.

Table 2

Summary of Cost Allocation Methodologies

	EGD	Union
Replacement of Existing Storage Assets	These projects consist of storage-related assets that are installed to replace EGD's existing assets supporting its storage operations. The nature of these projects serve to maintain the facilities and service capabilities whether they completely replace the asset, recondition the asset, or bring the asset into regulatory or environmental compliance. In all cases, the capital costs of these new facilities are directly assigned to Enbridge's accounts and/or entity of the original assets.	For any new storage projects that only replace Union's existing storage assets, the cost of those projects will be allocated to Union's storage operations on the same basis as the original assets.
Development of Incremental Storage Capacity	These projects consist of storage-related assets that are installed to provide EGD with new storage capacity or deliverability. The capital costs of these new facilities are directly assigned to EGD's unregulated storage operation.	For any new storage projects that replace and serve to improve operational efficiency and/or provide growth opportunities for Union's unregulated business, Union will directly assign to its unregulated storage operations that portion of costs associated with the increased efficiency and/or growth of that storage operation.
Replacement of Existing Storage Assets with a Capacity Enhancement Component	These projects consist of storage-related assets that are installed to replace EGD's existing assets and to provide incremental storage capacity or deliverability. Under this scenario, EGD's regulated utility operation would be charged the portion of the capital costs that it would have incurred if it were to have replaced the asset on a like-for-like basis. And, on that basis, its unregulated storage operation would be charged for the incremental costs that would have resulted from the higher capacity asset.	For any new storage projects that replace and serve to improve operational efficiency and/or provide growth opportunities for Union's unregulated business, Union will directly assign to its unregulated storage operations that portion of costs associated with the increased efficiency and/or growth of that storage operation.

28. Subsequent to amalgamation, Enbridge Gas retained Ernst & Young LLP (EY) to assist in the development of the Company's harmonized unregulated storage cost allocation methodology. Enbridge Gas is requesting that the OEB approve this methodology in Phase 2 of this Application, effective January 1, 2024. Evidence related to Enbridge Gas's proposed harmonized unregulated storage cost allocation methodology is set out at Phase 2 Exhibit 1, Tab 13, Schedule 2. Provided at Attachment 1 of that Exhibit is a report produced by EY which documents Enbridge Gas's proposed unregulated storage cost allocation methodology. Similar to the previous methodologies of EGD and Union, the report proposes classification of New Storage Assets into three categories for the purpose of allocation between regulated and unregulated storage operations. The categories are as follows:

Category 1 - New storage assets resulting in additional capacity and deliverability – allocated to unregulated storage.

Category 2 - New storage assets to maintain existing assets or replace existing end-of-life assets – allocated to regulated or unregulated storage, consistent with the allocation of the original asset.

Category 3 - New storage assets to replace and enhance existing assets – allocated to regulated and/or unregulated storage based on the underlying project driver.

29. As discussed in the Dawn to Corunna LTC Application (the LTC Application)[16], the Project provides equivalent design day storage withdrawal capability and equivalent storage injection capability as the seven compressors to be retired and abandoned. Therefore, the Project is categorized as a 'new storage asset to maintain existing assets or replace existing end-of-life assets'. This categorization is in line with the

[16] EB-2022-0086, Exhibit C, Tab 1, Schedule 1

proposed cost allocation methodology, which is consistent with the prior classification approaches under EGD and Union. For the seven compressors to be abandoned, 100 percent of the costs associated with the Project should be allocated to utility rate base. Therefore, Enbridge Gas asserts that the proposed cost allocation and 2024 proposed rate base of $338.8 million for the Project is appropriate.

30. This treatment would be consistent with past OEB decisions where 100 percent of the costs to replace regulated storage assets are allocated to utility rate base. In the 2015 Drill Wells in a Designated Storage Area Application[17] and subsequently in Drill Well TC 9H (Horiz#2) Moore 4-20-X Application[18], an injection and withdrawal (I/W) well was proposed to replace the deliverability of the Corunna Storage Pool that was lost due to the abandonment of two I/W wells and the conversion of one I/W well. Similarly, in 2017 Drill Wells in Dow Designated Storage Area Application[19], two horizontal gas storage wells were proposed to replace deliverability lost in the Dow-Moore Storage Pool due to the abandonment of five gas storage wells and one observation well. Finally, in Coveny and Kimball-Colinville Well Drilling Project Application[20], an I/W well was proposed to replace deliverability lost in the Kimball-Colinville Storage Pool for the abandonment of six gas storage wells due to integrity concerns.

31. Consistent with these past decisions, 100 percent of the costs associated with the Project should be allocated to the utility rate base as it replaces existing end-of-life assets that are allocated to regulated operations. Further, as discussed in Section

[17] EB-2015-0303.
[18] EB-2016-0378.
[19] EB-2017-0354.
[20] EB-2021-0248.

2, no new storage capacity or injection and withdrawal capability was created through integration of the operations of the EGD and Union storage systems. The Project maintains the current storage capacity, injection capability and withdrawal capability. Allocating 100 percent of the costs of the Project to regulated operations is consistent with the past treatment and proposed treatment of the cost associated with replacement of regulated assets related to storage.

4. Project Status and Cost Summary

32. The original cost estimate for the Project was developed in 2021 and filed in the LTC Application[21]. The Project received Leave-to-Construct approval in November 2022 and construction activities for the Project commenced in March 2023. The Project was placed in service November 30, 2023. Final clean-up is scheduled to be completed in summer of 2024.

33. The original cost estimate for the Project was $251.0 million and the current cost forecast is $377.0 million. A detailed description of Project costs is provided at Attachment 2.

5. 2024 Rate Base – Dawn to Corunna Replacement Project

34. Enbridge Gas is requesting the OEB approve utility rate base of $338.8 million applicable to the Project. Enbridge Gas further requests that the approved rate base and revenue requirement implications of the Project be reflected in the final approved 2024 rate base and revenue requirement and final 2024 rates.

[21] EB-2022-0086.

35. In the Phase 1 Settlement Agreement[22], Enbridge Gas agreed to remove the costs of the Project from proposed 2024 opening rate base and from the proposed 2024 Capital Budget. This is reflected in the Phase 1 Rate Order, where the 2024 interim revenue requirement does not include any rate base amounts or 2024 capital expenditures related to the Project.

36. The Phase 1 Settlement Agreement indicated that the determination of the rate base treatment of Project costs would be made in Phase 2.[23] Enbridge Gas proposes that 100 percent of the Project costs be attributed to regulated operations. The proposed rate base value of $338.8 million reflects the capital expenditures on the Project up to the end of 2024. Details of the costs incurred are included in the Post-Construction Financial Report provided at Attachment 2.

37. The proposed rate base value of $338.8 million includes the original indirect overhead allocations calculated for the Project costs in the Phase 1 Settlement Agreement. The increase in forecast expenditures for the Project results in a re-allocation of indirect overheads as shown in Table 1 of Attachment 2. This impacts the indirect overhead allocations for both the 2023 Bridge Year and 2024 Test Year as the amount of capital expenditures for the Project has increased in both years relative to the forecast at the Capital Update. Updating indirect overhead allocations for the Project based on capital expenditures to the end of 2024 would result in an increase in indirect overhead allocations of $5.2 million relative to the indirect overhead allocations included in the Phase 1 Settlement Agreement. It is not appropriate to include the increase/reallocation of indirect overheads in the proposed rate base for the Project. Doing so would result in ‘double counting’ of

[22] EB-2022-0200, Settlement Agreement, August 17, 2023.
[23] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17,2023, p.10.

indirect overheads since the overall amount of indirect overheads included in the 2023 capital forecast has not changed and is already included in 2024 opening rate base. The indirect overhead allocation for 2024 capital expenditures has been recalculated to reflect the Phase 1 Decision[24] and the $50 million decrease in capitalized indirect overheads.

6. Review of Alternatives

38. The Project enabled the retirement and abandonment of seven compressor units at the CCS to address known obsolescence, reliability and safety risks and maintains equivalent withdrawal and injection capability and working capacity at the Dawn Hub. Without alternatives to replace these units, Enbridge Gas would have stranded this storage space and would have been forced to purchase supply-side services to meet the demands of its customers. In the LTC Application[25], Enbridge Gas completed an alternatives assessment that included facility, non-facility, and repair and replace alternatives. Facility alternatives included Natural Gas Fired Compression, Electric Drive Motor Compression, and Liquified Natural Gas (LNG) Storage. Non-facility alternatives included supply-side alternatives and enhanced targeted energy efficiency alternatives. The NPS 36 pipeline was the preferred alternative as it provided an equivalent amount of capacity as the existing CCS compressor units and was the most economic alternative on the basis of cost per unit of capacity.

39. In March 2023 before proceeding to project execution, Enbridge Gas evaluated the cost of other facility alternatives as described in the LTC Application[26]. The facility alternatives also experienced cost increases. Despite the increase in Project costs,

[24] EB-2022-0200, Decision and Order, December 21, 2023.
[25] EB-2022-0086 Exhibit C, Tab 1, Schedule 1, March 21, 2022.
[26] Ibid.

the NPS 36 pipeline remained the most economic alternative to serve demand and address known obsolescence, reliability and safety risks and maintain equivalent withdrawal and injection capability and working capacity of the Dawn Hub.

40. The relative economics of the other facility alternatives discussed in the LTC Application[27] were re-assessed using updated cost information for materials, labour rates, engineering, project execution and contingency. The result of the analysis is presented in Table 3 and shows that the other facility alternatives experienced similar inflationary pressures. The NPS 36 pipeline remained the most economic alternative based on a NPV analysis in comparison to the other facility alternatives. The LNG storage alternative, as well as the repair and replace alternative, remained unable to satisfy the Project need as described in the LTC Application[28], and therefore Enbridge Gas did not re-evaluate these alternatives.

Table 3
Relative Economics of Facility Alternatives

Line No.	Alternative	Capacity (TJ/d)	Capital Cost ($ millions) (1)	O&M Cost ($ millions)	Unitized Capital Cost ($ millions/TJ/d)	NPV ($ millions)
		(a)	(b)	(c)	(d)	(e)
1	Natural Gas Fired Compression	680	402	3.88/yr	0.59	(332)
2	Electric Motor Drive Compression	680	457	8.07/yr	0.67	(435)
3	NPS 36 Pipeline	680	283	2.99/yr	0.42	(245)

Note:
(1) Capital costs include direct capital expenditures and interest during construction estimates as of March 2023, and do not include indirect overheads.

[27] EB-2022-0086 Exhibit C, Tab 1, Schedule 1, March 21, 2022.
[28] EB-2022-0086.

41. The non-facility alternatives discussed in EB-2022-0086 Exhibit C, Tab 1, Schedule 1, either alone or in combination with other facility and non-facility alternatives, could not avoid or reduce the proposed facilities needed to replace the storage capacity lost in comparison to the NPS 36 pipeline. Supply-side alternatives were investigated in detail in EB-2022-0086 Exhibit C, Tab 1, Schedule 1, Attachment 2 and included market-based storage, delivered services, and upstream pipeline capacity alternatives. The estimated cost of the supply-side alternatives ranged from approximately $0.5 billion to $4.7 billion more than the cost of the NPS 36 pipeline, which made these alternatives uneconomic. Each of these supply-side alternatives are distinctly different and the range of estimated costs is due to the variability of forecasted natural gas markets and assumptions, which include the impact of not replacing the capacity provided by the Project. Further, the supply-side alternatives would introduce an unacceptable level of incremental risk to EGD rate zone customers due to price volatility, contracting risk, and reduced flexibility and reliability. Before proceeding to project execution, no significant changes had occurred to warrant further investigation into non-facility alternatives and the NPS 36 pipeline remained the most economic alternative to meet the project need.

INTEGRATED STORAGE SYSTEM MODELLING AND ANALYSIS

1. Background

1. This document summarizes the process used to evaluate the integration of the EGD and Union storage systems due to the amalgamation of EGD and Union. This was identified in the Decision and Order for the Dawn to Corunna Project[1].

> The OEB is of the view that the concerns raised by Pollution Probe and Energy Probe regarding the need for an examination of the overall integration of storage assets between the legacy storage of Enbridge Gas Distribution and Union Gas Limited is best addressed in the upcoming Enbridge Gas rebasing proceeding.

2. Annually, Enbridge Gas completes a design day analysis that models all storage facilities and the interconnections with the adjoining transmission systems and upstream third-party pipelines. This analysis incorporates updates to parameters for existing storage, pipeline, and compressor facilities. Additionally, any new facilities are incorporated into the design day model. The primary purpose of this analysis is to determine the amount of withdrawal capability that is available from the storage system. Additionally, the model is used to determine the compression and pipeline facilities required to transport gas from the storage system and upstream supply pipelines, through the Dawn yard and into the Enbridge Gas transmission systems. This analysis is used to identify the withdrawal capability available for the utility and non-utility customers and evaluate potential facilities projects.

[1] EB-2022-0086, Decision and Order, page 13.

2. Storage Space

3. The amalgamation of EGD and Union provided Enbridge Gas with the opportunity to operate the storage systems as a single utility. The storage space associated with the Enbridge Gas storage pools is allocated to three categories: Union rate zones, EGD rate zone and Enbridge Gas non-utility.

Table 1
Enbridge Gas Storage Space

Line No.	Description	Storage Space (PJ)
		(a)
1	Union Rate Zones	100.0
2	EGD Rate Zone (1)	99.7
3	Enbridge Gas Non-Utility (2)	114.6
4	Total	314.3

Notes:
(1) Includes the Crowland storage pool (0.3 PJ)
(2) Does not include 7.9 PJ of storage space operated by Enbridge Gas and owned by Market Hub Partners Canada L.P., and Sarnia Airport Storage Pool L.P.

4. The Enbridge Gas storage system contains 35 storage pools. Each storage pool has unique characteristics and an associated amount of storage space and deliverability. Operating the storage pools as part of an integrated storage system does not create any additional storage space[2] in the individual storage pools. Therefore, the amalgamation of the two legacy storage systems did not create any additional storage space. Incremental storage space can only be created by investing capital to

[2] Also referred to as storage capacity and is the amount of gas stored in a storage pool.

develop new storage pools or increase the storage space of the existing storage pools.

3. Design Day Withdrawal Capability

5. Upon amalgamation, Enbridge Gas completed the following steps to develop a combined design day analysis:
   a) Develop an EGD design day analysis using the principles of the Union design day analysis.
   b) Create a new EGD design day hydraulic model that accurately models the EGD storage system and interconnects.
   c) Incorporate the Union storage system facilities into the new hydraulic model created for the EGD design day analysis.

   The process to develop the combined design day hydraulic model shown above is discussed in more detail in Appendix A (History of Hydraulic Modelling for Enbridge Gas's Storage Systems).

6. The combined design day analysis allowed Enbridge Gas to analyze the total withdrawal capability of the separate and combined storage systems. The results of this analysis are summarized in Table 2 and additional detail is included in Appendix B.

Table 2
Comparison of Winter 2021/2022 Design Day Withdrawal Capability

Line No.	Particulars (TJ/d)	Separate Models	Combined Model	Difference
		(a)	(b)	(c) = (b) - (a)
1	Union Rate Zones	3,866	3,850	(-16)
2	EGD Rate Zone	2,423	2,425	2
3	Totals	6,289	6,275	(-14)

7. The design day analysis concluded that combining the two storage systems did not create any incremental [3] design day withdrawal capability since the existing facilities were interconnected prior to amalgamation, the existing facilities were fully utilized, and no new facilities were added. Incremental design day withdrawal capability can only be created by investing capital to construct additional facilities.

8. Since the Natural Gas Electricity Interface Review (NGEIR)[4] Decision, the design day analysis for the Union rate zones storage was used to determine the maximum amount of withdrawal capability available. To date, utility customers in the Union rate zones have been allocated all the withdrawal capability required to meet design day demands regardless of the cost allocation to utility customers. This is proposed to be addressed in the 2024 Rebasing Application[5]. Any withdrawal capability above the utility customers' design day requirements is made available for non-utility customers. The non-utility storage business has invested significant capital to expand the capabilities of the system to create additional withdrawal capability and storage space.

[3] There is a minor decrease (- 14 TJ or 0.2%) in withdrawal capability however this is not considered significant for the purposes of this analysis.
[4] EB-2005-0551, OEB Decision and Order, November 7, 2006.
[5] EB-2022-0200, Phase 2, Exhibit 4, Tab 2, Schedule 5.

9. At the time of NGEIR, 100 percent of the EGD storage system was reserved for utility customers. This included 99.4 PJ[6] of space and 1.9 PJ/d of withdrawal capability[7]. Since NGEIR, the non-utility storage business, has developed both withdrawal capability and storage space. Following the MAADs Decision, a design day hydraulic model was created for the EGD rate zone. Like the Union rate zones, this model has been used to determine the maximum amount of withdrawal capability available. EGD rate zone utility customers are allocated 1.9 PJ/d of withdrawal capability. Any withdrawal capability above this amount is made available to the non-utility storage business.

10. Since amalgamation, Enbridge Gas has developed a combined hydraulic model to evaluate the storage system's combined capability. The combination of the storage systems has not created any incremental space or withdrawal capability since the separate systems were operating at maximum capability and fully utilizing all available facilities.

4. Deliverability Projects Since MAADs

11. Consistent with the NGEIR Decision, any projects to create storage space or withdrawal capability since amalgamation have been undertaken and paid for by the non-utility storage business.

12. As part of 2021/2022 Storage Enhancement Project[8], Enbridge Gas received approval from the OEB to (amongst other items):

[6] Not including 0.3 PJ of storage space at Crowland.
[7] 91.3 Bcf of space and 1,740 MMscfd of withdrawal capability as per EB-2005-0551.
[8] EB-2020-0256.

a) Re-route approximately 150 m of the Nominal Pipe Size (NPS) 20 Ladysmith pipeline to connect the Payne Pool pipeline and the Ladysmith pipeline within the existing Payne-Kimball Transmission Station;
b) Install 2.2 km of NPS 24 pipeline to connect the Payne Compressor Station to the Corunna Compressor Station; and
c) Drill a horizontal gas storage well (TL 9H) in the Ladysmith Storage Pool.

13. The combination of these facilities increased the design day withdrawal capability by 317 TJ/d. This project increased the non-utility withdrawal capability by investing capital to create two additional connection points between the storage systems. These facilities allow the Payne Pool to be filled and emptied through the Corunna Compressor Station and allows the Ladysmith Pool to flow directly to the Dawn Operations Centre by utilizing the NPS 20 Payne Pool pipeline. The connections constructed as part of this project provide additional flexibility to the system operator for filling and emptying storage. The flexibility increases reliability and resilience of the storage system to the benefit of all customers.

5. Flexibility to Manage Outages

14. The integration of the storage systems has provided Enbridge Gas with more flexibility to better manage outages required to complete construction and maintenance activities. As an example, in 2021 and 2022 Enbridge Gas completed the Corunna Meter Run Replacement Project at the Corunna Compressor Station. This project modernized the former meter area in the Corunna Compressor Station yard by removing piping and above ground meter runs that were no longer needed and replaced them with a series of headers and valving that provides increased operability, safety, and reliability to the system.

15. The construction was completed over two years by isolating the Corunna Compressor Station for a six-week period at the beginning of each construction season. Within each six-week period, a section of the yard was isolated for construction and the remaining yard was returned to service. At the end of the construction season the process was reversed.

16. During the yard outages, there was no activity at the EGD rate zone pools connected to the Corunna Compressor Station. Prior to the amalgamation, EGD would have had to purchase services from Union or from other participants in the market at Dawn to facilitate the outages to maintain deliveries from storage to meet customer demands. Since amalgamation, Enbridge Gas has been able to use the combined storage assets to integrate these types of outages into the overall storage operations by moving stored gas between the storage systems.

17. The additional operational flexibility does not create any additional storage space, injection capability or withdrawal capability.

APPENDIX A

A HISTORY OF HYDRAULIC MODELLING[9] FOR ENBRIDGE GAS'S STORAGE SYSTEMS

This document summarizes the history of the development of the combined hydraulic model used to analyze the design day withdrawal capability of Enbridge Gas's natural gas storage system.

Pre-2018

- Union developed a hydraulic model of its gas storage system and Dawn compressor station facilities in the 1980s.
- EGD developed a hydraulic model of its gas storage system and Corunna compressor station facilities around 2016.

2018

- MAADs Decision and Order from OEB (EB-2017-0306 and EB-2017-0307).
    - Integration opportunities start to be discussed.
- Amalgamation of EGD and Union
    - Separate rate zones are maintained.
    - Separate hydraulic models are maintained.
- A new EGD design day model was created using the Union design day methodology and associated analysis for winter 2017/2018 and winter 2018/2019 was completed.

[9] Hydraulic modelling software is a tool used to simulate natural gas storage, transmission, and distribution networks. Hydraulic modelling is used to perform pressure and flow calculations throughout a network. The software is used for analysis of closed conduit networks of pipes, regulators, valves, compressors, storage fields. Hydraulic modeling provides the analysis needed to make design, planning, and operating decisions.

  - This created a baseline (pre-amalgamation) model to the Union interconnection. The assumptions in this model did not consider any benefits from integration.

2019

- Enbridge Gas continued to use separate hydraulic models for the EGD and Union storage facilities for design day withdrawal capability analysis.
  - Annual updates completed.
  - Results from the EGD design day analysis were used as inputs to the Union design day analysis.
- Work starts to create a combined hydraulic model of the entire Enbridge Gas storage system.

2020

- Enbridge Gas continued to use separate hydraulic models for the EGD and Union storage facilities for design day withdrawal capability analysis.
  - Annual updates completed.
  - Results from the EGD design day analysis were used as inputs to the Union design day analysis.
- A new combined hydraulic model was completed for the entire Enbridge Gas storage system.
  - The combined model was created by adding the Union facilities to the EGD model.
  - Full system hydraulics were enabled by eliminating the defined delivery pressure set points at the interface points at Dawn between the separate EGD and Union models.

- Analysis was completed to compare the results of the separate hydraulic models and the new combined hydraulic model to ensure alignment of the modelling processes.
  - The results from the EGD hydraulic model were used as inputs to the Union hydraulic model.
    - This is consistent with the methodology applied prior to amalgamation since the EGD and Union storage systems are connected at Dawn.
    - The results from these two models were compared to the new combined hydraulic model.

  - The budget C2021 forecast winter 2023/2024 design day analysis was chosen for the comparison between the separate and combined models.
    - Since the new combined hydraulic model was built by adding the Union facilities into the EGD model, the analysis looked at the new combined hydraulic model design day withdrawal capability results of the Union facilities only, as the EGD facilities were unchanged.
    - The total withdrawal capability from the storage pools in the separate Union model was 3,925 TJ/d.
    - The total flow of the same Union facilities, including the same demand and supply, in the new combined model was 3,899 TJ/d. The difference in flow was 27 TJ or 0.7% between the separate and combined models. The difference between the separate and combined models is well within accuracy limits (i.e., confidence intervals) of the model’s basic input parameters (e.g., empirically derived storage field performance parameters). Therefore, the new combined hydraulic model accurately predicts the withdrawal capability of Enbridge Gas’s integrated storage system.

2021

- Enbridge Gas decided to use the new combined model as the official model going forward.
- The winter 2021/2022 design day analysis was completed using the official combined model. The analysis in this section of evidence is based on these winter 2021/2022 models.

APPENDIX B

DETAILED COMPARISON BETWEEN SEPARATE AND COMBINED WINTER 2021/2022 MODELS

Line No.	Pool (TJ/d)	Separate Models	Combined Model	Difference
		(a)	(b)	(c)= (a) - (b)
1	Airport	30	29	1
2	Bentpath	6644	6644	0
3	Bentpath East	00	00	0
4	Bickford	283	278	5
5	Bluewater	20	20	0
6	Booth Creek	0	0	0
7	Dawn 156	1367	1361	5
8	Dawn 167	0	0	0
9	Dawn 47-49	43	45	(-2)
10	Dawn 59-85	732	733	0
11	Dow A	73	72	1
12	Edy's Mills	0	0	0
13	Enniskillen	19	19	0
14	Heritage	7	8	(-1)
15	Mandaumin	24	24	0
16	Oil City	0	0	0
17	Oil Springs East	0	0	0
18	Payne	204	198	6
19	Rosedale	211	212	(-1)
20	Sombra	13	14	(-1)
21	St Clair	2	2	0
22	Terminus	128	128	0
23	Tipperary	0	0	0
24	Waubuno	66	64	2
25	Black Creek	82	80	1
26	Chatham D	11	11	0
27	Corunna	0	0	0
28	Coveny	0	0	0
29	Crowland	28	28	0

Line No.	Pool (TJ/d)	Separate Models	Combined Model	Difference
		(a)	(b)	(c)= (a) - (b)
30	Dow Moore	183	178	5
31	Ladysmith	507	506	2
32	Mid-Kimball	804	817	(-13)
33	Seckerton	0	0	0
34	South Kimball	627	632	(-5)
35	Wilkesport	181	172	8
36	Total	6,289	6,275	14

Dawn to Corunna Replacement Post Construction Financial Report

April 2024

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1. INTRODUCTION

Enbridge Gas Inc. (Enbridge Gas) applied to the Ontario Energy Board (OEB) on March 21, 2022, under Section 90 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B, for an Order granting Leave-to-Construct (LTC) to the Dawn to Corunna Replacement Project (the Project).

The LTC for the project was filed with the OEB on March 21, 2022. Enbridge Gas progressed its normal course detailed design and construction activities. Enbridge Gas began issuing requests for proposals (RFP), ordered materials, re-evaluated initial cost estimates and commenced construction. These and other activities occurred during the COVID-19 pandemic and the Ukraine war. The Project was constructed during a period where other major pipelines were being constructed in North America and an inflationary economic environment. These factors, along with materials delays and unexpected challenges and conditions encountered during construction impacted actual costs for the Project, in particular materials costs, pipeline construction costs and facilities construction costs, as set out in this Post Construction Financial Report (PCFR).

The Project consists of approximately 20 km of Nominal Pipe Size (NPS) 36 steel natural gas pipeline and associated station facilities.[1] The Project enables Enbridge Gas to abandon and retire seven reciprocating compressor units located at the Corunna Compressor Station due to identified reliability, obsolescence, and safety concerns. The compressor units were replaced by the 20 km of NPS 36 steel natural gas pipeline.

The OEB issued its decision (the Decision) granting LTC for the Project on November 3, 2022[2].

In accordance with Condition of Approval (COA) 2(b)iv of the Decision, on December 8, 2023, Enbridge Gas informed the OEB that the Project[3] had been placed into service on November 30, 2023.

In accordance with COA 7.a of the Decision, on February 15, 2024, Enbridge Gas filed a Post Construction Report for the Project with the OEB.

Enbridge Gas is filing this PCFR to provide guidance and explanation for actual cost and forecasted cost of the Project. This PCFR includes root cause analysis and variance analysis of project costs, schedule and scope compared to the Project estimate filed in the Dawn to Corunna LTC[4] proceeding, including the extent to which contingency was utilized.

2. SUMMARY

The estimated direct capital cost for the Project set out in the LTC application was $206.4 million[5]. There was also an indirect overhead allocation of $44.4 million, for a total cost estimate of $250.8 million. The direct capital estimate was based on a parametric and bottom-up approach to the

[1] EB-2022-0086, Exhibit E, Tab 1, Schedule 1.
[2] EB-2022-0086, Decision and Order, November 3, 2022.
[3] In-service date Letter to the OEB.
[4] EB-2022-0086.
[5] EB-2022-0086, Exhibit D, Tab 1, Schedule 1.

preliminary engineering design that was then verified using:

- a high-level cost per meter estimate provided by a reputable pipeline contractor.
- a high-level station cost completed by the contracted engineering service provider.
- a comparison to the final Panhandle Reinforcement Project (PRP) cost for the NPS 36 pipe installation completed in 2017. The Project estimate of $5.9 million per kilometer was approximately 26% higher than the $4.7 million per kilometer cost for PRP.

The Project direct capital cost is $302.6 million. This represents a variance of $96.2 million from the Project direct capital cost estimate filed in the LTC application. The indirect overhead allocation has increased with the increase of the direct capital cost and is now $74.3 million which equates to a total Project cost of $376.9 million. As set out in Phase 2 Exhibit 1, Tab 13, Schedule 4, these Project costs result in a proposed rate base value of $338.8 million. Enbridge Gas discussed the potential for cost variances during the Dawn to Corunna LTC proceeding[6] and this PCFR highlights the drivers for the Project cost variances.

During project development it was observed that costs were increasing above the value stated in the LTC. At the time, Enbridge Gas undertook a high-level review to confirm that the Project remained the best alternative to address the requirements resulting from the abandonment and retirement of the compressor units at the Corunna Compressor Station.

Enbridge Gas conducted streamlining exercises reviewing scope to find ways to mitigate increasing project cost. These exercises resulted in design changes to both Dawn and Corunna stations that resulted in scope reduction. The cost avoidance of the streamlining exercise was estimated to remove $8.0 million of material cost and an additional $4.8 million of contractor cost.

As noted in the LTC application at Exhibit D, Tab 1, Schedule 1, the Project cost estimate for direct capital was a Class 4 estimate, following the Company's Cost Estimating and Management Standard. A Class 4 estimate, as defined by the American Association of Cost Engineers (AACE), will have a range of accuracy of -30% to +50% ($144.5 million to $309.6 million) for direct capital costs. The $96.2 million variance results in Project direct capital costs falling within this range.

The variance from the initial direct capital estimate and indirect overhead allocation to the current forecast is shown in Table 1.

[6] EB-2022-0086.

Table 1
Cost Variances by Category

Reference	Category ($ millions)	Estimate	Actuals + Forecast to end of 2024	Variance
1	Project Management	5.7	6.5	0.8
2	Engineering	3.5	6.9	3.4
3	Land	15.3	15.2	(0.1)
4	Materials	48.4	76.9	28.5
5	Pipeline Construction	49.1	74.8	25.7
6	Facilities Construction	22.0	84.0	62.0
7	Construction Support	22.8	23.6	0.8
8	Commissioning and Start Up	0.4	1.1	0.7
9	Retirement	13.1	9.3	(3.8)
10	Interest During Construction (IDC)	2.1	4.3	2.2
11	Contingency	24.0	-	(24.0)
12	Indirect & Overhead	44.4	74.3	29.9
13	TOTAL	250.8	376.9	126.1

Section 3 of this PCFR explains five root causes which contributed to substantially all of the cost variances. Section 4 provides a more detailed explanation of these variances by individual cost category.

3. COST OVERAGE ROOT CAUSES

Total cost variance for the Project can be attributed to the following five root causes: a) estimate to bid variance; b) higher than expected inflation; c) material delivery delays; d) unforeseen construction challenges; and e) indirect overhead allocation. Each of these root causes is explained below, with an estimation of the overall impacts of each and an indication of which line items in Table 1 are impacted by each root cause.

3.1. Bid Prices Relative to Estimate

The largest root cause of the overall variance is the difference between the forecast bids from contractors for the Project work and the actual bid prices. This relates to the fact that the Company had not yet issued or awarded its RFP at the time of the LTC application. Forty million ($40.4 million) of the overall variance is due to the increase in bid prices relative to the estimate.

Enbridge Gas issued separate RFPs for the pipeline and facilities portions of the Project.

The nature of an RFP is competitive as the contractors are competing against each other.

Contractor prices are generally reflective of the competitive market for their services at the time of an RFP and the degree of complexity and risk associated with the work. A contract strategy was used to select the most relevant and pre-qualified proponents for the RFP, based upon interest, availability, and related experience in Ontario.

The RFP responses showed bid prices substantially higher than Enbridge Gas's estimates. The high-level reasons for the difference include timing (inflation and labour price impacts), refined scope of work and better clarity of the construction location through site visits, geotechnical surveys, and environmental surveys.

After receiving the initial bids, alternate contract structures were requested and evaluated for both the pipeline and facilities RFPs in an attempt to reduce price.

The impacts of this root cause are seen in two lines on Table 1 – Pipeline Construction and Facilities Construction.

The cost variance breakdown by each of the two construction scopes (pipeline and facilities) activity categories is as follows.

Table 2
Comparison of Contractor Estimate to Contractor Bid

Construction Activity ($ millions)	Cost Estimate	Bid Price	Variance Estimate to Bid
Pipeline	$49.1	$58.3	$9.2
Facilities	$22.0	$52.1	$30.1
Total	$71.1	$110.4	$39.3

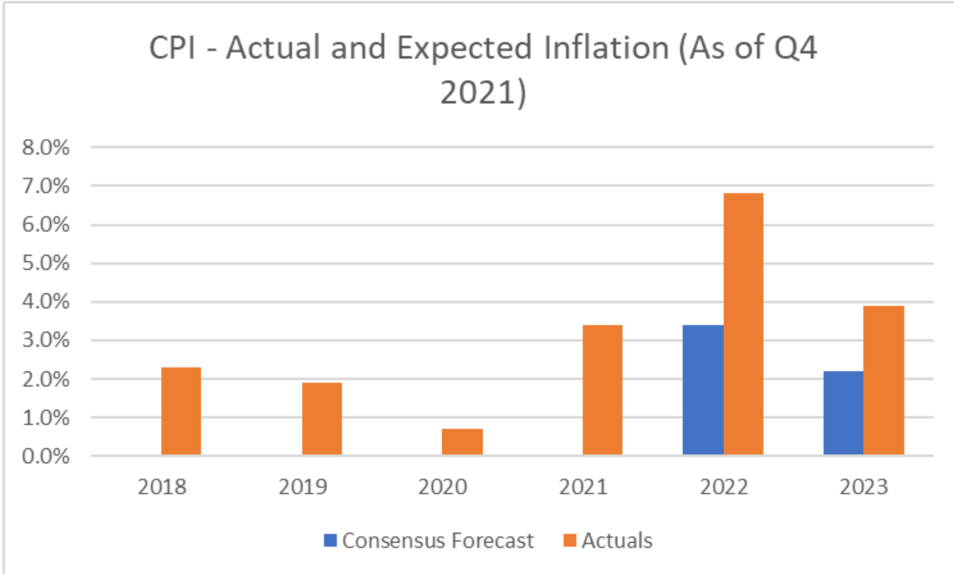
More details on the contracting strategies, processes, and results for each of the pipeline and facilities portions of the Project are set out in Section 4.

3.2. Inflation

Another main root cause of the cost increases is the impact from inflation on the cost components of the Project. This relates in large part to the fact that there were extraordinarily high inflationary impacts in the period between the time when the LTC cost estimate was created, when the RFP process was completed, and when the Project was executed. The estimates were created in Q4 2021 and used historical data.

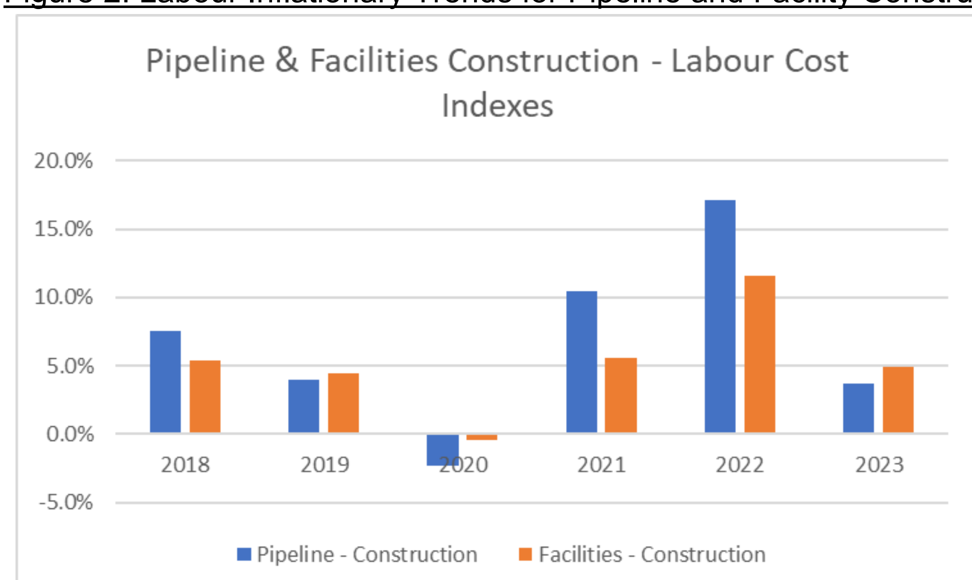
In general, inflation rates during the period between the estimates (in Q4 2021) and the RFP response dates (September 2022) and the Project execution dates (through 2023) were much higher than expected. This is shown in Figure 1.

Figure 1: Actual and Expected Inflation



Higher than expected inflation was also experienced for labour costs across the pipeline industry, at levels in excess of the overall level of inflation. The figure below reflects that contractor costs for both pipeline and facilities have seen higher inflationary drivers starting in late 2021 through to 2023 when the new construction was placed into service. These inflationary drivers are higher than historical trends and exceeded the escalation assumptions used in the LTC estimate. This would have had an influence on prices bid by the Prime Contractor. While not specific to the Project, these tables do illustrate the overall cost pressures facing industry participants like Enbridge Gas for large pipeline and facilities projects in the past couple of years. Those cost pressures are even higher than the (already high) general level of inflation.

Figure 2: Labour Inflationary Trends for Pipeline and Facility Construction



Inflation also had significant impacts to materials costs for the Project. Purchase orders for materials were issued from June 2022 through September 2023. Supply chain data for that period shows higher than normal inflationary pressure due to two key events: the COVID-19 pandemic and the Russia/Ukraine war. At the same time, global steel production experienced inflationary price increases that far exceeded normal trends as well as the (already high) overall level of inflation. The global price for pipe has been trending up since Q4 2020 with an increase roughly 125% higher in June 2022 when the pipe was ordered for the Project.

Enbridge Gas attributes $20.6 million of the overall variance to the incremental costs associated with inflation. The inflation impacts are seen in multiple line items within Table 1, including Materials, Pipeline Construction and Facilities Construction. The largest impact, amounting to $15.9 million, is seen in the materials costs. More details are set out in Section 4.

3.3. Material Delivery Delays

A third root cause of the cost increases is the delays in material delivery experienced during Project execution. Material delivery delays were only experienced for station scope.

The initial project schedule was developed with input for what was the expected long lead material timelines, as determined by Enbridge's supply chain market intelligence. Typical examples of long lead material for this project would include large bore valves, large bore pipe, large bore fittings and flanges, engineered components, instrumentation, actuators, and prefabricated buildings. Throughout the procurement process Enbridge Gas confirmed that manufacturers expected delivery dates met project timelines prior to issuing a purchase order. There were over 1500 purchase orders issued for the Project. The majority of purchase orders were for station/facilities scope. There was a significant trend of slippage across all material categories from expected manufacturer's delivery dates. Enbridge Gas applied a rigorous material expediting effort in an attempt to maintain supplier delivery dates, which was found to achieve limited success. Key materials needed to advance construction arrived later than expected resulting in delays and requiring inefficient construction practices and higher contractor costs.

The delays in material delivery caused interruptions and adjustments to the schedule and increased costs for the execution of the Project.

Enbridge Gas attributes $19.2 million of the overall variance to the incremental costs associated with material delivery delays, which impacted the station scope of the Project.

Material delays did not impact pipeline scope. Pipeline for the Project was completed in a single mill run comprised of multiple orders for what is essentially a homogenous component. Scheduling risk is typically lower when fewer and similar components are required for a project. Pipe for the Project was ordered from a single supplier early in the construction process and did not experience any delivery delays.

Contrary to pipelines, stations/facilities require a significantly more diverse group of components to be constructed, which can result in scheduling complexity and risk. Station/facility scope was impacted by material delays due to a significantly larger number of purchase orders (compared to pipeline scope), quantity and variability of many different components and the dependency of having the correct component available to build and install. The impacts of these costs are seen in the Project Management and Facilities Construction lines in Table 1. More details are set out in Section 4.

3.4. Unforeseen Construction Challenges

A fourth root cause of the Project cost increase is the impacts from unforeseen construction challenges experienced during Project execution.

The contracted RFP prices for the components of the Project were based upon the parameters set forth in the bid documents. This included information about the scope of the Project, detailed plans and drawings and a planned project schedule. The bids provided and accepted were premised on those details. As is typical in large construction projects, where new information or requirements emerge that impact the Project, there will be a new / altered scope of work and timeline with an associated change in cost. While a contract could be created to minimize the risk (such as a lump sum contract), the up-front cost of such a contract would be significantly higher as the contractor would be assuming substantially more risk. Instead, the RFP costs and project schedule were premised upon assumptions about normal working conditions and the accuracy of plans and drawings. If those assumptions were different than what was experienced during construction, the contractors were permitted to make claims for additional costs.

Enbridge Gas encountered two main construction challenges during Project execution, which together increased project costs by $21.6 million.

During construction within the Dawn Operations Centre, it was discovered that a buried section of NPS 42 pipe that had to be removed was 2.5 metres deeper than expected. The extent of the excavation and backfill to this area of the site added $8 million to the overall construction costs. This is seen in the Facilities Construction line in Table 1.

The execution of the pipeline portion of the Project was negatively impacted by abnormally wet weather during construction. The construction area received 99% more rain during June, July and August than the 30-year average, leading to a large number of shutdown days. This factor added $13.6 million to the overall construction cost and can be seen in the Pipeline Construction line in Table 1.

Cost impacts from this root cause are also seen in the Project Management category.

3.5. Indirect Overhead Allocation

A fifth root cause of the Project cost increases relates to indirect overhead costs.

Indirect overheads are a function of the total core capital cost and the overhead rate for the in-service year. The allocation is made based on the value (cost) of each project, meaning that where the costs of one project increases relative to the total, then the allocation to that project increases and the allocation to other projects decreases. Additionally, where the overall indirect overhead costs go up, then the amount allocated to each project increases.

Enbridge Gas attributes $29.9 million of the overall variance to the incremental costs associated with indirect overheads. The increase in indirect overheads is due to the increase in direct capital cost of the Project and an increase to the overhead rate applied from the time of the original cost estimate in Q4 2021. The overhead rate is updated with each budget and forecast cycle to reflect the most current estimate of the direct capital spend and indirect overheads. The $29.9 million Indirect Overheads increase is comprised of $7.5 million for the rate increase from 23.1 percent to 25.7 percent and an additional $22.4 million due to the increase in direct capital costs.

The updated indirect overhead costs do not impact the proposed rate base value for the Project. Please see Phase 2 Exhibit 1, Tab 13, Schedule 4 for a discussion of the rate base impacts of the Project.

4. VARIANCE EXPLANATIONS BY CATEGORY

The following subsections provide a further sub-categorization and explanation of the major variances by cost category. For convenience, the Table 1 summary of the variances by cost category is reproduced below.

Table 1
Cost Variances by Category

Reference	Category ($ millions)	Estimate	Actuals + Forecast to end of 2024	Variance
1	Project Management	5.7	6.5	0.8
2	Engineering	3.5	6.9	3.4
3	Land	15.3	15.2	(0.1)
4	Materials	48.4	76.9	28.5
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9	Retirement	13.1	9.3	(3.8)
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11	Contingency	24.0	-	(24.0)
12	Indirect & Overhead	44.4	74.3	29.9
13	TOTAL	250.8	376.9	126.1

In the following subsections, Enbridge Gas sets out a high-level explanation for each of the cost variances. In some cases, additional explanation and linkage to the root causes has been included to provide further information and context.

4.1. Project Management

Sub-Category	Variance ($ millions)	Comments
Project Management	0.8	The overage was due to schedule extension due to weather and material delays for direct labour in the areas of procurement, quality management, document management, commissioning, project controls, public relations, stakeholder management, and insurance.
Total category	0.8	

4.2. Engineering

Sub-Category	Variance ($ millions)	Comments
Pipeline design	0.2	Additional boreholes were required to complete feasibility assessment and final horizontal directional drilling(HDD) design at Black Creek. Higher cost to develop mechanized welding procedures and non-destructive examination (NDE) criteria. Field survey cost were higher than budget due to more effort required for right of way staking and to collect pipeline data.
Facilities design	3.2	Facilities design overage is driven by scope maturity from preliminary design to detailed design at the Dawn Operations Centre and Corunna Compressor. The final facilities design grew from 70 drawings at preliminary design stage to over 1750 drawings at detailed design stage resulting in an increase of 20,000 engineering hours exceeding the original engineering budget. The original estimate provided by the engineering service provider was not sufficient to complete the detailed facilities scope. Original engineering effort was estimated at 13,800 hours and grew to over 34,600 hours.
Total category	3.4	

4.3. Land

Sub-Category	Variance ($ millions)	Comments
Landowner resolutions	(0.1)	Temporary land use was less than estimated as the contractor was able to complete the pipeline installation using a smaller workspace.
Total category	(0.1)	

4.4. Materials

Pipeline		
Sub-Category	Variance ($ millions)	Comments
Currency exchange	0.5	Pipeline price variance attributable to the reduction in the Canadian vs. US dollar between the time of estimate and the time of payment, which is in US dollars.
Inflation	14.3	Pipeline cost was $14.3 million higher due to inflation at the time of purchase compared to the time the estimate was completed (a cost increase of 126 percent). The global price for pipe has been trending up since Q4 2020 with an increase of roughly 125% higher in June 2022 when the pipeline was ordered for the Project. The price of longitudinal seam pipe reached a peak of over $2,320 USD/Ton when the pipe was being ordered compared to a price of around $1,150 USD/Ton when the initial estimate was created.
Facilities		
Sub-Category	Variance ($ millions)	Comments
Mechanical equipment, buildings, actuators, controls, and instrumentation	8.1	The cost variance for this category is attributed to higher manufacturing cost for engineered components (e.g. filter/separators, drain tanks, receivers, RTU buildings) and higher market cost for ultrasonic meters and gas chromatograph equipment.
Pipe	4.2	Station pipe cost was $4.2 million higher due to inflation and market conditions at the time of purchase compared to the time the estimate was completed. Though station pipe was ordered in Q4 2022, and global steel prices were trending down, the available qualified vendors was reduced after Western governments, including Canada, placed sanctions on Russia. In support and alignment to the Canadian government's sanctions on Russia, Enbridge Gas did not issue new purchase orders to businesses associated with Russia. This limited Enbridge Gas's ability to source the appropriate station pipe to meet quality and specifications. Ultimately the pipe was ordered from a pipe mill in

		the United Kingdom and the cost was found to be three to five times higher than historical trends.
Valves, fittings	1.4	The number of valves and fittings increased from preliminary design to detailed design. In addition to the increase in the number of valves, higher purchase price for valves was realized and associated with supply chain disruptions along with higher-than-normal inflationary pressure on steel commodities.
Total category	28.5	

4.5. Pipeline Construction

Sub-Category	Variance ($ millions)	Comments
Bid to estimate	9.2	On July 18th, 2022, a comprehensive RFP package was issued to four selected proponents for Project pipeline scope. To eliminate the risks associated with a reimbursable contract (such as time and materials), the form of contract was base lay (i.e., lump sum broken into a quantity of lineal meters of construction) plus unit prices (UPI) for items that could not be quantified and priced in advance without adding significant risk premium to the contract. Examples of UPI include rock excavation, matting, and non-native backfill. Similarly, crew standby caused by adverse weather conditions was elected to be compensated on a time and material basis to avoid adding significant risk premiums to the base lay contract. On September 26th, 2022, proposals were received from each of the four proponents. Two contractors were ultimately shortlisted through a comprehensive multi-round evaluation process that carefully assessed the technical, commercial, and socio-economic aspects of each proposal against predefined and weighted scoring criteria. The commercial evaluation involved equalization of contractor-quantity estimates for certain unit prices to ensure the best available information was used for the initial estimate and evaluation. The selected contractor demonstrated excellent scoring across all evaluation criteria and offered the lowest (equalized) proposal price at $58.3 million. This represented a $7.3 million reduction from the average RFP submissions, which was achieved through bid clarifications and negotiations. The $58.3 million proposal price was further composed of $44.6 million in base lay and $13.7 million in unit prices. The second lowest proponent's price was more than $2 million higher than the successful contractor.

Sub-Category	Variance ($ millions)	Comments
		The pipeline estimate to bid variance of $9.2 million can be attributed to the following: • The expectation of a tight labour market for pipeline construction services in 2023 with both Coastal Gas Link and Trans Mountain pipelines under construction. This was confirmed by follow-up discussions with each contractor while negotiating the final pipeline contract. • Greater scope clarity and risk identification was available with the 2022 Pipeline RFP, relative to the 2021 RFI. The contractor's bid price reflected the actual number of road crossings, water crossings, and trenchless crossings captured in the detailed design and as observed by a site tour of the proposed right of way. • Higher labour rates due to inflation reflected in the national union rates for skilled trades.
Weather	13.6	Construction of the Dawn to Corunna pipeline was impacted by abnormally wet weather which caused delays and increased costs to the pipeline construction. The pipeline experienced 32 full shutdown days (full right of way) and 23 partial shutdowns days (portions of right of way). A comparison of rainfall data was conducted for the construction location, and the amount of rain in 2023 doubled compared to previous years. The construction area received 99% more rain during June, July and August than the 30-year average. Environment Canada data shows that the 30-year average rainfall in that location is 244 mm over that period, while 484 mm of rain was experienced during the construction. Appendix C provides a summary of the rainfall experienced at various locations versus average historical rainfall. Appendix D provides construction pictures that reflect some of the wet weather challenges. The cost increases attributable to the wet weather is $13.6 million. Significant efforts were made to mitigate the impacts of wet weather including: • Pumping water off the right of way to remove accumulated water. • Installing culverts and other drainage mitigation measures. • Prioritizing dry-weather activities during favorable conditions and rescheduling non-weather dependent tasks.

Sub-Category	Variance ($ millions)	Comments
		• Installing temporary access roads and matting systems. The Project utilized schedule float to mitigate timing impacts with the addition of increased resources, longer working hours during scheduled days and working non-scheduled days to complete the pipeline construction. An ultimate impact was an extension to the in-service date.
Scope	2.9	UPI quantities increased from estimate to completion of construction for items like, sand, gravel, erosion fence, asphalt, and geotechnical material.
Total category	25.7	

4.6. Facilities Construction

Sub-Category	Variance ($ millions)	Comments
Bid to estimate	30.1	On July 18th, 2022, a comprehensive RFP package was issued to eight pre-qualified proponents for the facilities scope. Also included in the RFP was a request for bundling discounts if a contractor was to be awarded multiple scopes (i.e., economies of scale and similar cost efficiencies related to single contractor managing a greater amount of work relative to multiple contracts managing the same volume of work). Proposals were received from six of the eight proponents on September 26, 2022. An initial review of proposals resulted in the elimination of two proponents for the facilities scope based on pre-defined criteria that set out that each proponent must be self-performing for at least 51% of the scope. The remaining four proponents were then scored on pre-defined RFP evaluation criteria (with consideration to technical, commercial, and socio-economic aspects) and the lowest score proponent was also eliminated, leaving three shortlisted proponents. The three shortlisted proponents on average had bids for the facilities scope that were 204% higher than the estimated contract price with an average bid value of $63.6 million, which was significantly higher than anticipated. Upon comparison of the preliminary and detailed design for the Facilities scope, it was noted that the contractors' estimated labour-hours, diameter inch welding, electrical cable length, and cut/fill were substantially higher from what was considered in the initial estimate. The final station

Sub-Category	Variance ($ millions)	Comments
		design was more extensive, complex, and larger in scope than the estimate at the preliminary design stage. These differences can be attributed to scope refinement from preliminary design to detailed design. The significantly higher average bids from proponents led to a review of the facilities scope which determined that a portion of the facilities scope could be streamlined at both Corunna and Dawn. The selected proponents were asked to reduce their bid price based upon the remaining facilities scope. This resulted in the two selected contractors reducing their bids by $4.8 million. While the RFP was ongoing, Enbridge Gas became aware of emerging delays to Company-supplied materials (for the construction contractors). Additionally, Enbridge Gas took steps to further refine the scope for facilities and anticipated revisions to drawings that were expected to arrive over the period of February 2023 to June 2023. In response to these developments, Enbridge Gas revisited the proposed contract structure (lump sum) and decided to change to actual cost (reimbursable) with a fixed fee incentive believing this would be a more adaptive contract structure for the higher potential for design changes and material delays during post-award. In response to new schedule information and the change to contract structure, the proponents returned proposals that reflected an average decrease of $0.4million to the previous lump sum pricing. After close examination and clarification of scope, the lowest priced actual cost-plus fixed fee proposals for Dawn facilities and Corunna Compressor Station facilities were selected, which included two different contractors. One contractor was selected for the Dawn facilities work and the other for the Corunna Compressor Station work. The selected contractors demonstrated excellent scoring across all evaluation areas and offered the lowest valued proposal price of $52.1 million for the facility scopes. This represented a $11.5 million reduction from the average RFP submission, which was achieved through bid clarifications and negotiations. The facilities estimate to bid variance of $30.1 million can be attributed to the following items: • The expectation of a tight labour market for construction services in 2023 with both Coastal Gas Link and Trans Mountain pipelines under construction. • The greater design definition provided with the 2022 Facilities RFP relative to the 2021 RFI

Sub-Category	Variance ($ millions)	Comments
		exercise conducted with more limited contractor participation. • Higher labour rates due to inflation reflected in the national union rates for skilled trades. • Scope maturity from preliminary design to detailed design. The number of facilities drawings at the preliminary design was 70 compared to 1,756 after detailed design.
Construction complexity/scope	12.7	Corunna station experienced a variance of $1.0 million due to construction complexity and scope change. During construction at Dawn, a portion of a NPS 42 pipe that had to be removed prior to installing the new piping design was 2.5m deeper than as-built drawings had indicated. This led to an increase to the scope for excavation and backfill throughout the Dawn Facility scope for an increase of $10.7 million. The increased effort for excavation and backfill also caused a schedule extension which led to increased contractor costs for supervision and indirect of $1.0 million
Material delays	19.2	Global supply chain challenges and extended engineering timelines resulted in receiving material later than the planned construction schedule causing reduced productivity for fabrication and mechanical work at both Dawn and the Corunna Compressor Station. Material delivery issues were experienced throughout 2023 for station pipe, large bore valves, small-bore valves, fittings, flanges, actuators, filter/separators and meters. Material delays resulted in higher costs for fabrication and installation at Dawn and the Corunna Compressor Station. Contractor costs for the Corunna Compressor Station scope were $2.7 million higher for fabrication and $1.0 million higher for schedule compression. Contractor costs were $2.8 million higher due to material delays, higher labour and equipment use greater than initial bid. Contractor costs for the Dawn Facility scope were $3.0 million higher for fabrication, $1.8 million higher for schedule compression efforts to meet the in-service date, and $7.9 million higher for a longer schedule to complete work at Dawn and Corunna, which resulted in increased costs for supervision, office support and equipment.
Total category	62.0	

4.7. Construction Support

Sub-Category	Variance ($ millions)	Comments
Third-party support	0.8	During construction, the cost of inspections increased due to the schedule extension. The cost of construction support was offset by avoiding more challenging specialty service providers for hot work. Environmental costs were lower due to a reduction in the number of endangered species permits required.
Total category	0.8	

4.8. Commissioning and Start Up

Sub-Category	Variance ($ millions)	Comments
Third-party support	0.7	Initial estimate underestimated the cost for commissioning at Dawn and the Corunna Compressor Station.
Total category	0.7	

4.9. Compressor Retirement

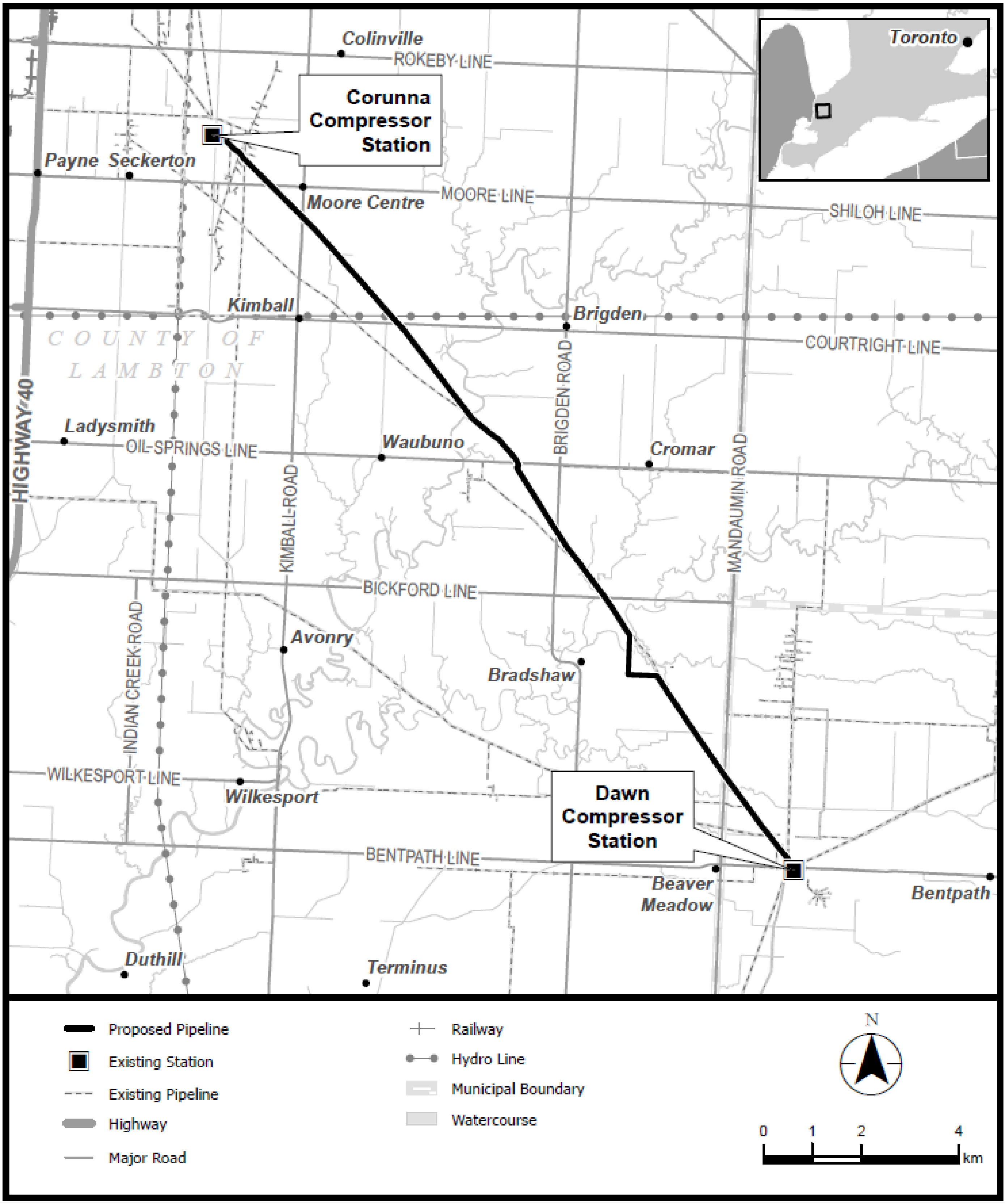
Sub-Category	Variance ($ millions)	Comments
Retirement	(3.8)	The reduction is attributed to a decrease in the budgeted amount for abandonment of compressors at the Corunna Compressor Station.
Total category	(3.8)	

4.10. Interest During Construction (IDC)

Sub-Category	Variance ($ millions)	Comments
IDC	2.2	The variance in IDC is attributable to the extended Project duration and increased cost relative to the original estimate.
Total category	2.2	

APPENDIX A

Project Mapping


Colinville
ROKEBY LINE
Corunna Compressor Station
Toronto
Payne
Seckerton
Moore Centre
MOORE LINE
SHILOH LINE
Kimball
Brigden
COURTRIGHT LINE
COUNTY OF LAMBTON
HIGHWAY 40
Ladysmith
OIL SPRINGS LINE
Waubuno
BRIGDEN ROAD
Cromar
MANDAUMIN ROAD
KIMBALL ROAD
BICKFORD LINE
INDIAN CREEK ROAD
Avonry
Bradshaw
WILKESPORT LINE
Wilkesport
Dawn Compressor Station
BENTPATH LINE
Beaver Meadow
Bentpath
Duthill
Terminus
Proposed Pipeline
Existing Station
Existing Pipeline
Highway
Major Road
Railway
Hydro Line
Municipal Boundary
Watercourse
N
0
1
2
4
km

APPENDIX B

Average Rainfall

Table B1:
Environment Canada; 1981 – 2010 Average Rainfall (mm) – Project Area

Line No.	Location	June	July	August	Total
		(a)	(b)	(c)	(d) = (a+b+c)
1	Sarnia Airport	83.1	78.5	78.5	240.1
2	Petrolia Town	90.1	75.7	81.8	247.6
3	Average	86.6	77.1	80.15	243.85

Table B2
Stantec; 2023 Actual Rainfall (mm) – Project Site

Line No.	Location	June	July	August	Total
		(a)	(b)	(c)	(d) = (a+b+c)
1	Dawn Plant	107	144	168	419
2	Stanley Line	90	182	176	448
3	Oil Springs Line	134	175	174	483
4	Waubuno Road	111	304	174	589
5	Tecumseh Road	92	232	164	488
6	Average	106.8	207.4	171.2	485.4

APPENDIX C

Pipeline Construction

Bridgen Pipe Yard (January 2023)

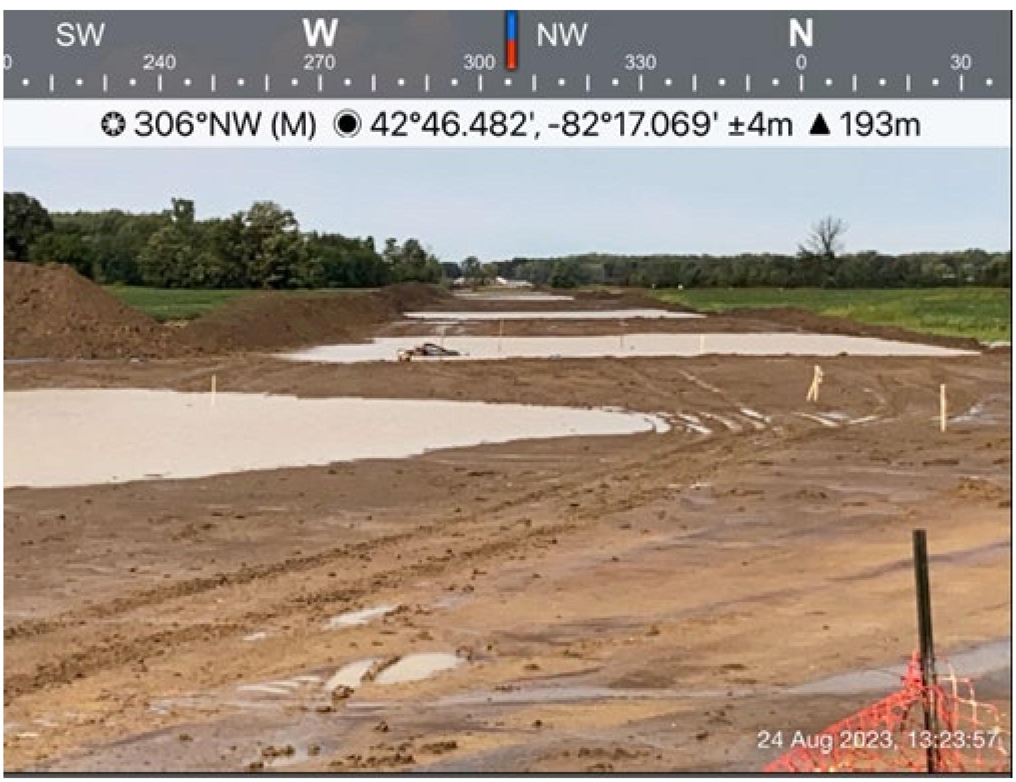
Right of way (June 2023)
Access road to Bear Creek HDD

Pipe stringing along right of way (August 2023)

Water on right of way (August 2023)

Open cut road crossing (August 2023)

Wet soil shutdown following striping of topsoil (August 2023)



Black Creek dam and pump crossing (September 2023)

Black Creek Restoration (November 2023)

Bear Creek HDD (September 2023)

Lake Tanks for Hydrotest (October 2023)

APPENDIX D

Facilities Construction

Dawn North Yard and Dawn West Yard (February 2024)

Dawn West Yard Flooded (January 2024)

Measurement Building Removal (June 2023)

Dawn North Excavations (May 2023)

Dawn North Yard New Piping (January 2024)

Dawn North Yard Unforeseen Site Conditions (July 2023)

Dawn West Yard (February 2024)

Corunna Yard ABC Header (October 2023)

ENERGY COMPARISON INFORMATION REPORT

GILMER BASHUALDO-HILARIO, MANAGER DEMAND FORECASTING & ANALYSIS
JENNIFER MURPHY, MANAGER ENERGY TRANSITION PLANNING

1. In its Phase 1 Decision and Order[1], the OEB directed Enbridge Gas to review the energy comparison information in its informational and marketing materials, including its website,
   a) To determine whether it fully discloses what is being compared and on what basis, and what assumptions are being used for the comparison;
   b) To make any necessary corrections to the information, or remove the information completely; and,
   c) To file a report on the review it undertook and the actions it took as a result of the review.

2. The purpose of this evidence is to present Enbridge Gas's review of the energy comparison information it produces. This evidence is organized as follows:
   1. Energy Comparison Information
   2. Energy Comparison Assumptions
   3. Review of Energy Comparison Information
   4. Future Considerations

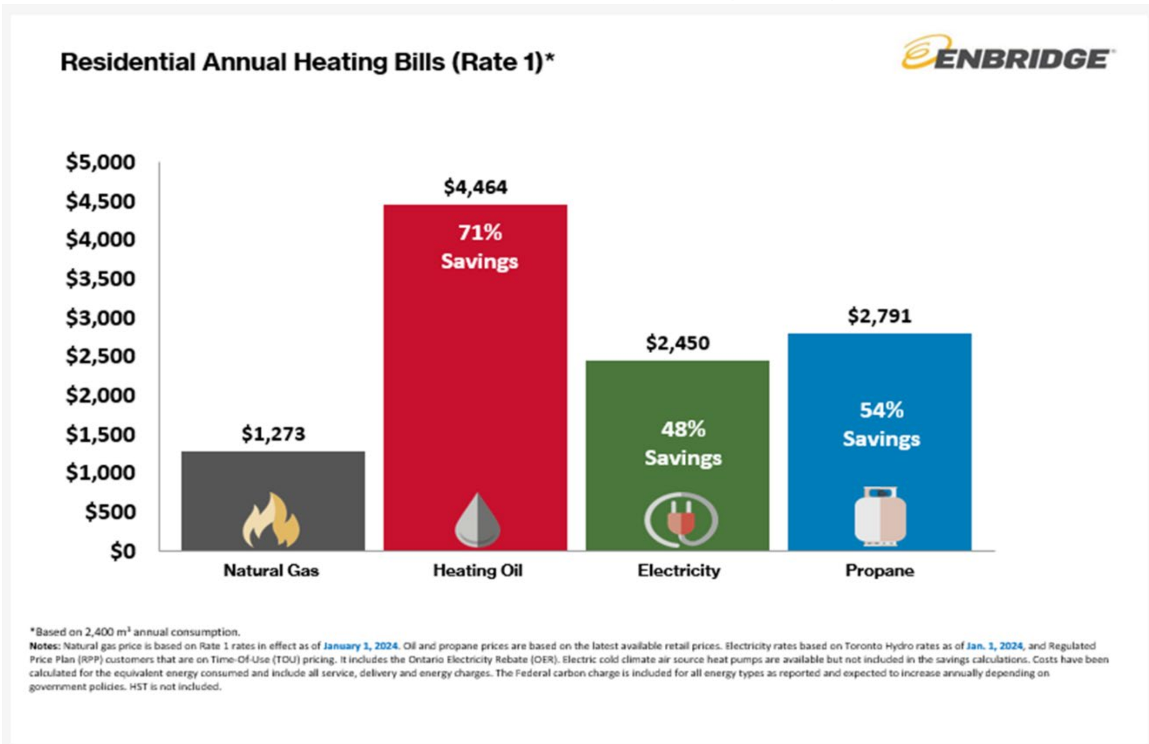
1. Energy Comparison Information

3. Enbridge Gas prepares energy comparison information on a quarterly basis to create printout and digital marketing materials to inform potential conversion customers and other third-party stakeholders with respect to potential new conversion attachments (e.g., renovators). It is also used to support stakeholder

[1] EB-2022-0200, Decision and Order, December 21, 2023, p.47.

briefings (e.g., OEB, government, HVAC industry). An example of the energy comparison information chart is presented below. The example corresponds to the "Residential Annual Heating Bill (Rate 1)" produced for the January 2024 QRAM update.

Figure 1: Residential Annual Heating Bill (Rate 1) – January 2024



4. The energy comparison information illustrates an estimated energy equivalent annual heating bill[2] for conversions from three standard existing energy sources (i.e., heating oil, propane, and electric resistance heating) to natural gas, for a typical residential consumer in Rate 1, Rate M1 and Rate 01 (North East and North West). Greater details regarding the specific assumptions underpinning the energy comparisons are provided later in Section 2 of this evidence.

[2] Annual heating bill implies heat load (space heating) and base load (water heating).

2. Energy Comparison Assumptions

5. The natural gas consumption used in the comparison represents typical residential consumption of an Enbridge Gas customer in Rate 1, Rate M1 and Rate 01 (North East and North West). The term 'typical' implies a representative annual consumption for a residential Enbridge Gas customer. Typical consumption for a residential customer in the EGD rate zone (Rate 1) is 2,400m^3 and for the Union rate zones (Rate M1 and Rate 01 North East and North West) is 2,200m^3.

6. Typical consumption for a residential customer is comprised of both a heat load and base load component which represents whole-home heating[3]. The energy comparisons assume space heating for heat load and water heating for base load.

7. All comparisons for the alternative energy sources (i.e., heating oil, propane, and electric resistance heating) are based on an energy-equivalent annual consumption adjusted by efficiency factors. Energy-equivalent implies that all fuels (natural gas, electric resistance heating, heating oil and propane) are evaluated on a comparable basis of energy, namely gigajoules (GJ). First, the typical annual residential natural gas consumption (measured in m^3) is converted into units of energy (GJ). These energy units (GJ) are then converted into kilowatt-hours (kWh) for electricity and litres (L) for heating oil and propane. Conversions for all fuel sources are calculated using the relevant conversion factors and adjusted further based on the applicable efficiency factors assumed. The cost savings for natural gas is derived by subtracting the annual bill amount (annual cost) for each alternative energy source from the annual bill amount (annual cost) for natural gas. The annual bill amount is estimated for each energy source by multiplying the annual consumption by its

[3] Whole-home heating assumes heat load (space heating) and base load (water heating) and does not include cooling.

respective unit cost.

8. Initial upfront costs/setup costs, such as costs related to purchasing and installing heating equipment, are not included in the energy comparison calculations.

9. The energy comparison information excludes harmonized sales tax (HST) in the unit cost for all energy sources. Federal carbon charge (FCC) is included in the unit costs where applicable[4].

10. The information does not illustrate a consumer energy equivalent annual heating bill for conversions from:
    a) Non-natural gas solutions to other non-natural gas solutions (for example, from heating oil to electric cold climate air source heat pumps (electric ccASHPs)).
    b) Natural gas to non-natural gas solutions (for example, from natural gas to electric ccASHPs).
    c) Existing electric ccASHPs to natural gas.

11. Enbridge Gas has no ability to cause consumers to fully convert to non-natural gas solutions (such as electric ccASHPs). Regarding electric ccASHPs specifically, there are several reasons why providing consumer annual heating bill information regarding conversions to electric ccASHPs would result in incomplete and potentially misleading information:

[4] Effective November 9, 2023, the FCC has been paused for a 3-year period on heating oil when used exclusively for home/building heating. Sourced from: Fuel Consumption Levies in Canada. https://natural-resources.canada.ca/our-natural-resources/domestic-and-international-markets/transportation-fuel-prices/fuel-consumption-taxes-canada/18885#https://www.nrcan.gc.ca/our-natural-resources/domestic-international-markets/transportation-fuel-prices/fuel-consumption-levies-canada/18885

a) Enbridge Gas understands that there is a wide range of potential upfront costs required to convert a home to an electric ccASHP, and therefore the energy comparison between natural gas and an electric ccASHP is best done by including upfront costs. Assessing the upfront costs required to convert a home to an electric ccASHP configuration requires consideration of several factors, which results in a more complex analysis than assessing the upfront costs required to convert a home to a natural gas furnace configuration. For example, in addition to the cost of the electric ccASHP itself, a home could also require electrical panel upgrades, exterior service upgrades from the electric utility, internal wiring upgrades, duct work improvements, etc. These costs can vary widely from home to home, and for this reason it is difficult for Enbridge Gas to develop an average customer lifetime cost-effectiveness analysis. Customers looking to switch to an electric ccASHP would need to engage an HVAC contractor to better understand the cost-effectiveness of an electric ccASHP based on an inspection of their home and determining conversion requirements. This is not information known by Enbridge Gas.

b) Providing consumer conversion cost information related to conversions to electric ccASHPs without consideration of the electric supply-side requirements and implications within the relevant area would not be appropriate. Supply-side requirements, including the costs required to generate, transmit, and distribute electricity, are critical factors with respect to a community’s energy security/reliability. This is not information known by Enbridge Gas and would need to be determined by the electric utility serving the relevant area.

12. While Enbridge Gas does not provide consumer annual heating bill information regarding conversions to electric ccASHPs, the Company's website[5] notifies consumers that high-efficiency non-natural gas alternatives, such as electric ccASHPs, are available and provides a link to reputable sources (i.e., NRCan) for more information regarding the end-use equipment and encourages potential customers to contact an HVAC consultant about energy options, building considerations and costs.

2.1 Calculation of Energy Equivalent Annual Consumption adjusted by Efficiency Factors

13. Table 1 provides the consumption assumptions used in the energy comparisons for a typical residential customer.

Table 1
Natural Gas Consumption for a Typical Residential Customer
(Annual)

Line No.	Rate Zone	Rate Class	Consumption (m^3)
			(a)
1	EGD Residential	Rate 1	2,400
2	Union Residential	Rate M1	2,200
3	Union Residential	Rate 01 North East	2,200
4	Union Residential	Rate 01 North West	2,200

14. Table 2 provides the calculation of energy-equivalent annual natural gas consumption adjusted by efficiency factors for the alternative energy sources (i.e.,

[5] Enbridge Gas. Community Expansion. https://www.enbridgegas.com/residential/new-customers/community-expansion

heating oil, propane, and electric resistance heating)[6]. The energy equivalent consumption of 2,400 m^3 natural gas for the EGD rate zone (Rate 1) based on the calculation provided in Table 2 is approximately 21,448 kWh for electric resistance heating, 2,678 L for heating oil and 3,788 L for propane. Similarly, the energy equivalent consumption of 2,200 m^3 natural gas is approximately 19,829 kWh for electric resistance heating, 2,476 L for heating oil and 3,518 L for propane in the Union South rate zone (Rate M1). For the Union North rate zone both North East and North West (Rate 01), the energy equivalent consumption of 2,200 m^3 natural gas is approximately 19,642 kWh for electric resistance heating, 2,452 L for heating oil and 3,484 L for propane. The energy equivalent annual consumption may vary slightly due to any updates in heat value, efficiency factors and/or conversion formulas from sources used as reference in the calculations.

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[6] Energy conversions are sourced from the Canada Energy Regulator website: Energy conversion tables https://apps.cer-rec.gc.ca/Conversion/conversion-tables.aspx?GoCTemplateCulture=en-CA
Natural gas heat values used in conversion calculation of m^3 to GJ are sourced from the following:

a) EGD rate zone: sourced from the Rate Handbook, Rate 1 Residential Service
b) Union rate zones: sourced from: Unit of Measure Conversion Information | Enbridge Gas. https://www.enbridgegas.com/storage-transportation/doing-business-with-us/unit-measure-conversion-information

Table 2
Calculation of Energy Equivalent Annual Consumption adjusted by Efficiency Factors

Line No.	Energy Source	Calculation
	(a)	(b)
1	Electric Resistance Heating	$a = b \times (c \times d) \times (g \div h)$
2	Heating Oil	$a = b \times (c \times e) \times (g \div i)$
3	Propane	$a = b \times (c \times f) \times (g \div j)$

a = Energy Equivalent Annual Consumption adjusted by Efficiency Factors
b = Typical annual residential natural gas consumption
2,400m^3 assumed for EGD rate zone (Rate 1)
2,200m^3 assumed for Union rate zone (Rate M1, Rate 01 North East and North West)
c = Conversion from m^3 to GJ (Natural Gas)
d = Conversion from GJ to kWh (Electric Resistance Heating)
e = Conversion from GJ to Litres (L) (Heating Oil)
f = Conversion from GJ to Litres (L) (Propane)
g = Efficiency factor assumed (Natural Gas equipment)
h = Efficiency factor assumed (Electric Resistance Heating equipment)
i = Efficiency factor assumed (Heating Oil equipment)
j = Efficiency factor assumed (Propane equipment)

2.2 Calculation of Efficiency Factors

15. Each energy source's efficiency factor is calculated for total consumption and is comprised of a heat load (space heating) and base load (water heating) component. The total efficiency factor is derived by calculating the weighted average of the individual efficiency factors for space and water heating as provided

in Table 3[7].

Table 3
Current Efficiency Factors for a Typical Residential Customer

Line No.	Particulars	Natural Gas	Electric Resistance Heating (2)	Heating Oil	Propane
		(a)	(b)	(c)	(d)
	EGD Rate Zone – Rate 1				
1	Space Heating (SH)	89%	100%	84%	84%
2	Domestic Water Heating (DWH)	68%	98%	65%	68%
3	Total Efficiency Factor (1)	83%	99%	78%	79%
	Union Rate Zones – Rate M1 and Rate 01 North East and North West				
4	Space Heating (SH)	88%	100%	84%	84%
5	Domestic Water Heating (DWH)	68%	98%	65%	68%
6	Total Efficiency Factor (1)	83%	99%	78%	79%

Notes:
(1) Total Efficiency Factor is calculated by applying 70% weighting for space heating and 30% weighting for water heating
(2) In the January 2024 version of the chart, this title is termed 'Electricity'. It has been changed here to align with the updates discussed in section 3, implemented as a result of Enbridge Gas's review.

16. The efficiency factors used are based on a weighted-average efficiency for each fuel type and not the highest possible efficiency available for each fuel type.

[7] Individual efficiency factors are sourced from: Provincial Regulation (O.Reg 509/18) https://www.ontario.ca/laws/regulation/180509?search=Ontario+Regulation+509#BK12 https://www.ontario.ca/laws/regulation/180509?search=Ontario+Regulation+509, Federal Regulation, Energy Efficiency Regulations, 2016 (justice.gc.ca), https://laws-lois.justice.gc.ca/eng/regulations/SOR-2016-311/index.html and its Amendment 15 Canada Gazette, Part 2, Volume 153, Number 12: Regulations Amending the Energy Efficiency Regulations, 2016 (Amendment 15) https://www.gazette.gc.ca/rp-pr/p2/2019/2019-06-12/html/sor-dors164-eng.html and Enbridge 2021 Residential End User Survey.

2.3 Calculation of Unit Cost

17. The energy cost per unit used for each energy source is based on the latest actual data available at the time of comparison[8]. Analysis is updated quarterly and corresponds to the timeline of Enbridge Gas's OEB-approved Quarterly Rate Adjustment Mechanism (QRAM) Applications.

Unit Cost for Natural Gas ($ per m3)

18. The natural gas pricing is sourced directly from Enbridge Gas's OEB-approved QRAM Applications. The system expansion surcharge (SES) of $0.23 per m^3 is also factored in the unit cost for Community Expansion energy comparisons.

19. Table 4 provides an example of the natural gas pricing calculation used in the January 2024 Energy Comparison and is representative of a typical residential customer in the EGD rate zone (Rate 1).

[8] Natural gas prices are updated in January, April, July, and October through OEB-approved Quarterly Rate Adjustment Mechanism (QRAM) filings. For electricity prices Time of Use (TOU) rates are updated in May and November of each calendar year. Changes in TOU in May are reflected in the July energy comparison and TOU changes in November are reflected in the January energy comparison. Ontario Energy Rebate (OER) is reflected as per the current available announcement at the time of comparison.

Table 4
Typical Residential Customer Total Bill Impacts (1)
EGD Rate Zone

	Rates Effective:	1-Jan-24	
Volume	m^3		2,400
Customer Charge	$		274.56
Distribution Charge	$		227.23
Load Balancing	$		39.05
Transportation	$		113.79
Sales Commodity	$		282.18
Federal Carbon Charge	$		297.36
Cost Adjustment	$		
Gas Supply	$	48.74	
Transportation	$	3.98	
Delivery	$	(13.50)	39.22
Total Sales with Cost Adjustments	$		1,273.39
Total unit rate $/m³ (2)	$/m³		0.531

Notes:
(1) Sourced from EB-2023-0330, Exhibit A, Tab 3, Schedule 1, p. 1, EGD Rate Zone.
(2) Total unit rate $/m³' is representative of the unit cost.

Unit Cost for Home Heating Oil ($ per Litre)

20. The pricing for home heating oil is sourced from Statistics Canada[9] and is based on the latest information available at the time of comparison.

[9] Average retail prices for gasoline and fuel oil, by urban centre; Toronto, Ontario; Household heating fuel; Cents per litre, StatsCan, CANSIM (v735163).

21. Table 5 provides an example of the heating oil pricing calculation used in the January 2024 Energy Comparison for a typical residential customer in the EGD rate zone (Rate 1).

Table 5
Home Heating Oil (HHO) (1)

Month	Federal/Provincial Carbon Tax Charge HHO (2)	HHO (v735163) (3)	HHO (excl. GST/HST) (4)
	(a)	(b)	(c)
23-Jan	13.41	221.6	196.1
23-Feb	13.41	196.9	174.2
23-Mar	13.41	186.5	165.0
23-Apr	17.38	184.5	163.3
23-May	17.38	173.6	153.6
23-Jun	17.38	169.2	149.7
23-Jul	17.38	168.5	149.1
23-Aug	17.38	181.8	160.9
23-Sep	17.38	192.9	170.7
23-Oct	17.38	195.8	173.3
23-Nov	17.38	188.4	166.7
Total Cents/L	166.7		
Total unit rate $/L (5)	1.667		

Notes:
(1) All prices in cents/litre.
(2) Sourced from https://www.canada.ca/en/revenue-agency/services/forms-publications/publications/fcrates/fuel-charge-rates.html#confacnatgas
(3) Sourced from the Conference Board of Canada (CANSIM) - v735163. Prior to Nov. 2023, the federal carbon charge was included within the pricing.
(4) Values under column (c) are derived by dividing the value under column (b) by 1.13
(5) ‘Total unit rate $/L’ is representative of the unit cost for the last reported month (in this example 23-Nov)

Unit Cost for Electricity ($ per kWh)

22. Unit costs for electricity are based on the prices published in the distributor's website or rate order. The electricity distributor assumed for each Enbridge Gas rate class is detailed in Table 6.[10] Monthly customer charges are not included in the unit cost for electricity[11] for a fair comparison since every home connects to electricity and monthly fix charges are being paid by all homeowners regardless of their heating fuel choice.

Table 6
Electricity Distributor

Line No.	Rate Class (Residential Sector)	Distributor
		(a)
1	Rate 1	Toronto Hydro
2	Rate M1	London Hydro
3	Community Expansion Projects (1):	
	Rate 1	Hydro One
	Rate M1	Hydro One
	Rate 01 (North East and North West)	Hydro One

Note:
(1) Most community expansion projects are located in rural areas and the assumption used in the energy comparison is that most rural areas are serviced by Hydro One.

23. The energy comparisons assume Time of Use (TOU) pricing (as opposed to Tiered pricing and Ultra-low pricing). There is not a material difference between the three options that would substantially impact the savings.

[10] Community Expansion projects assume service by Hydro One Networks Inc. and as of January 1, 2024, Hydro One is in the final year of transitioning to fully fixed distribution rates and therefore there is no longer a distribution volumetric rate. As a result, the First Nations Delivery credit is no longer considered in the Energy Comparisons effective January 2024.
[11] Monthly customer charges refer to the 'service charge' for both Toronto Hydro and Hydro One and 'Fixed Monthly Charge' for London Hydro.

24. The load percentages assumed for TOU pricing are sourced from the annual OEB Regulated Price Plan Report. Table 7 provides the current assumed load percentages.

Table 7
TOU Load Percentages

Line No.	Particulars	Load % Assumed
		(a)
1	On Peak	19%
2	Mid Peak	18%
3	Off Peak	63%

Note:
(1) Sourced from OEB Regulated Price Plan Price Report - November 1, 2023, to October 31, 2024.

25. The Ontario Energy Rebate (OER) for electricity distributors is also incorporated in the pricing for electricity. It is applied at the time of comparison as per the latest announcement published by the OEB and the Government of Ontario[12].

26. Tables 8 and 9 provide an example of the electricity pricing calculation used in the January 2024 Energy Comparison for a typical residential customer in the EGD rate zone (Rate 1). Unit TOU rate for the electricity is calculated by taking the weighted average of unit prices for ‘on peak’, ‘mid peak’, and ‘off peak’ and the related loads as provided in Table 8. Then, total unit rate before OER is determined by adding the unit TOU rate to the remaining electricity bill charges (delivery and regulatory) as provided in Table 9. Finally, the OER is applied to the total unit rate to determine the final total unit rate with OER.

[12] Effective November 1, 2023, the OER increased to 19.3% and is still in effect and therefore the current assumption used in the energy comparisons.

Table 8
Regulated Price Plan - TOU and OER

Line No.	Particulars	Cents/kWh (1)	% of Load (2)
		(a)	(b)
1	On Peak	18.2	19%
2	Mid Peak	12.2	18%
3	Off Peak	8.7	63%
4	Unit TOU rate- cent/kWh (3)	11.14	
5	Unit TOU rate - $/kWh (4)	0.1114	
6	Ontario Energy Rebate (OER) (5)	19.3%	

Notes:
(1) TOU rates effective November 1, 2023.
(2) Sourced from OEB Regulated Price Plan Price Report - November 1, 2023, to October 31, 2024.
(3) Value derived by taking the weighted average of columns (a) and (b) for lines 1-3.
(4) Value derived by dividing line 4(a) by 100.
(5) OER effective November 1, 2023, per OEB Newsroom release dated October 19, 2023.

Table 9
Toronto Hydro-Electric System Limited
Residential Service Classification (1)

		Rates Effective 1-Jan-2024	
(a)	Service Charge (2)	45.30	$/month
(b)	Transmission Rate - Network Service Rate	0.01224	$/kWh
(c)	Transmission Rate - Line and Transformation Connection Service Rate	0.00845	$/kWh
(d)	Wholesale Market Service Rate	0.0041	$/kWh
(e)	Capacity Based Recovery (CBR)	0.0004	$/kWh
(f)	Rural or Remote Electricity Rate Protection Charge (RRRP)	0.0007	$/kWh
(g)	Rate Rider for Disposition of Deferral/Variance Accounts	0.00444	$/kWh
(h)	Rate Rider for Disposition of Capacity Based Recovery Account	(0.00013)	$/kWh
(i)	Unit TOU rate - $/kwh (3)	0.1114	$/kWh
(j)	Total unit rate $/kWh (4)	0.142	$/kWh
(k)	OER (Total unit rate $/kWh * OER %)) (5)	0.027	$/kWh
(l)	Total unit rate $/kWh with OER (6)	0.114	$/kWh

Notes:
(1) Sourced from EB-2023-0054 Decision and Rate Order, Toronto Hydro-Electric System Limited. Effective and Implementation Date January 1, 2024, Residential Service Classification.
(2) Excluded for energy comparison purposes.
(3) See Table 8 for detailed calculation of Unit TOU rate - $/kwh.
(4) Value for (j) derived by summing (b) + (c)+ (d) + (e) + (f) + (g) + (h) + (i).
(5) OER of 19.3% effective November 1, 2023, per OEB Newsroom release dated Oct. 19, 2023. Value for (k) derived by multiplying (j) by OER of 19.3%.
(6) Total unit rate $/kWh' and 'Total unit rate $/kWh with OER' are representative of the unit cost. Value for (l) derived by subtracting (k) from (j).

Unit cost for Propane ($ per Litre)

27. Propane prices are sourced from EDPRO website and assumes pricing for 2,500-4,499 litres[13]. Pricing is derived by calculating the average of the daily prices of the latest calendar month available at the time of comparison.

28. Propane pricing is not available for the Union North (Rate 01) rate zone; therefore, the Union North Propane price assumption is based on the latest available retail prices in Rate M1 Union South rate zone discounted by 10%.

29. Table 10 provides an example of the propane pricing calculation used in the January 2024 Energy Comparison for a typical residential customer in the EGD rate zone (Rate 1). At the time of comparison, November 2023 was the last full month of data available and therefore the average calculation is based on November.

[13] EDPRO is one of the largest propane solution providers in Ontario, privately and locally owned, serving customers across Southwestern Ontario. The propane prices are daily published on its website: https://edproenergy.com/residential/. EGD rate zone (Rate 1) references price from Zone 5 and Union rate zones (Rate M1, Rate 01) references price from Zone 1.

Table 10
Propane Prices for Residential Rate 1 Customer

Ending Value Oct. 31, 2023 (cents/L) 64.4 (1)

Date	$/L	Cents/L	Daily Price Change (2)	Carbon Tax (3)	Total
1-Nov-2023	0.644	64.4	0	0.1006	0.7446
2-Nov-2023	0.646	64.6	0.2	0.1006	0.7466
3-Nov-2023	0.646	64.6	0	0.1006	0.7466
4-Nov-2023	0.637	63.7	-0.9	0.1006	0.7376
5-Nov-2023	0.637	63.7	0	0.1006	0.7376
6-Nov-2023	0.637	63.7	0	0.1006	0.7376
7-Nov-2023	0.637	63.7	0	0.1006	0.7376
8-Nov-2023	0.634	63.4	-0.3	0.1006	0.7346
9-Nov-2023	0.634	63.4	0	0.1006	0.7346
10-Nov-2023	0.634	63.4	0	0.1006	0.7346
11-Nov-2023	0.634	63.4	0	0.1006	0.7346
12-Nov-2023	0.634	63.4	0	0.1006	0.7346
13-Nov-2023	0.634	63.4	0	0.1006	0.7346
14-Nov-2023	0.634	63.4	0	0.1006	0.7346
15-Nov-2023	0.634	63.4	0	0.1006	0.7346
16-Nov-2023	0.629	62.9	-0.5	0.1006	0.7296
17-Nov-2023	0.629	62.9	0	0.1006	0.7296
18-Nov-2023	0.635	63.5	0.6	0.1006	0.7356
19-Nov-2023	0.635	63.5	0	0.1006	0.7356
20-Nov-2023	0.635	63.5	0	0.1006	0.7356
21-Nov-2023	0.642	64.2	0.7	0.1006	0.7426
22-Nov-2023	0.638	63.8	-0.4	0.1006	0.7386
23-Nov-2023	0.635	63.5	-0.3	0.1006	0.7356
24-Nov-2023	0.635	63.5	0	0.1006	0.7356
25-Nov-2023	0.635	63.5	0	0.1006	0.7356
26-Nov-2023	0.635	63.5	0	0.1006	0.7356
27-Nov-2023	0.635	63.5	0	0.1006	0.7356
28-Nov-2023	0.635	63.5	0	0.1006	0.7356
29-Nov-2023	0.635	63.5	0	0.1006	0.7356
30-Nov-2023	0.644	64.4	0.9	0.1006	0.7446

November Monthly Average	63.627
Carbon Tax:	10.060
Total Cents/L	73.687
Total unit rate $/L (4)	0.737

Notes:
(1) Date of the last recorded daily price change from the previous month
(2) Source: https://edproenergy.com/residential/ ; Zone 5, 2,500-4,499 litres
(3) Source: https://www.canada.ca/en/revenue-agency/services/forms-publications/publications/fcrates/fuel-charge-rates.html
(4) ‘Total unit rate $/L’ is representative of the unit cost

3. Review of Energy Comparison Information

30. Enbridge Gas continuously reviews its energy comparison information to reflect changing market conditions and stakeholder feedback. Throughout 2023, prior to the Phase 1 Decision, which directed Enbridge Gas to review and update its energy comparison information[14], the Company reviewed and made updates to its energy comparison information. In 2024, following the Phase 1 Decision, Enbridge Gas again reviewed and made updates to its energy comparison information. Both the 2023 and 2024 reviews/updates are described below.

3.1 2023 Review of Energy Comparison Information

31. Enbridge Gas reviewed its energy comparison materials throughout 2023. The reviews resulted in updates to the information presented, as described below:
    a) Enbridge Gas updated a footnote on the Company's energy comparison information to clarify that the savings calculations used in the chart does not reflect electric ccASHPs, and that the FCC is expected to increase annually.
    b) The Community Expansion marketing package, which is used as a general information package for all actively in-market communities to educate customers on the benefits of natural gas, cost effective potential, steps to apply to natural gas, what to expect with billing and an explanation of the system expansion surcharge (SES), was revised to indicate that the energy comparison of conversion from electricity to natural gas reflected electric resistance heating and did not include electric ccASHPs. A redlined version of the updated October 2023 package is provided at Attachment 1.
    c) An additional change was made to the attachment package to include a link to the NRCan website and a statement encouraging consumers to contact

[14] EB-2022-0200, Decision and Order, December 21, 2023, p.47.

an HVAC consultant about energy options, building considerations and costs.

d) Existing marketing packages were updated to include information about Enbridge Gas's Demand Side Management (DSM) programs and include a link to NRCan's website for information regarding alternative technologies, such as electric ccASHPs to provide customers with information regarding alternative heating options.

e) Language concerning energy comparison, both online and in the Community Expansion marketing materials, was revised to align with changes made to the attachment package in April 2023.

3.2 2024 Review of Energy Comparison Information

32. As a result of the directive for Enbridge Gas to review and update its energy comparison information, if necessary, the Company again reviewed and made updates to its energy comparison information to further clarify its uses.

33. As part of the review, Enbridge Gas conducted an internal survey requesting employees who use the energy comparison information to provide feedback regarding how they use the information. The results indicated that the energy comparison information is being used by employees for both internal and external purposes as discussed previously in paragraph 3 of this evidence. Additionally, in some instances, the information is provided to builders.

34. Enbridge Gas has determined that the current energy comparison chart is most applicable to conversion customers and will no longer be shared with builders. When builders or developers request this information, Enbridge Gas will direct them to contact an HVAC provider.

35. The company also reviewed its website and printed materials that use this comparison chart to ensure the footnotes and titles were consistent and clear and that all changes have been reflected.

36. The updated footnote on the chart added in 2023 made clear that the electric component in the energy comparison did not include ccASHPs. The term 'electricity' was replaced with the term 'electric resistance' on the bar label of the energy comparison to provide enhanced clarity.[15] Furthermore, effective April 1, 2024, additional updates were made to the disclaimer to increase clarity regarding the assumptions underpinning the energy comparison. An example of the most recent energy comparison (Rate 1) produced for April 2024 QRAM update is provided at Attachment 2. As shown in Attachment 2, the disclaimer now incorporates the following clarities:
    a) Estimated bill amount is illustrative of a typical residential customer and implies a representative annual consumption which includes both space and water heating.
    b) Resulting savings are for illustration purposes only. Consumption levels and savings will vary based on customer region or zone of residence, appliance, appliance efficiency and household characteristics, lifestyle, and energy prices. Customers are directed to refer to their actual utility bills for specific actual usage, pricing, and totals.
    c) The OER % discount assumed (19.3%) is now specified.
    d) Sources for heating oil and propane pricing have been added.
    e) Clarity regarding a paused FCC for heating oil is noted.
    f) Targets specific users, in particular customers considering conversions from electric resistance, heating oil and propane to natural gas.

[15] Change in terminology implemented on the April 2024 Energy Comparisons.

g) Stipulates that upfront/set up costs are not included.
h) Additional advice has been added encouraging customers to consult an HVAC service provider regarding specific energy options, building consideration, cost estimates appropriate to the specific needs, and electric related costs.

37. The cost calculator tool was removed from the Community Expansion pages of enbridgegas.com and all references to it removed from marketing messaging. Individuals work directly with a company representative to understand their cost savings. This was done to ensure accuracy and align with changes made to the attachment package in 2023.

38. Enbridge Gas believes the changes made in 2023 and the additional changes described above as a result of this directive further ensure that Enbridge Gas's marketing materials are accurate, that information provided is clearly described and fully disclosed.

4. Future Considerations

39. Enbridge Gas will continue to review the energy comparison information in the future and will make required changes to assumptions when available and have impact on savings. Enbridge Gas will also continue to review and update all marketing material, including the customer attachment package, website, print and, digital to reflect changing market conditions and stakeholder feedback.

40. For the reasons stated above in Section 2, adding electric ccASHP to the energy comparison information is complex. Enbridge Gas intends to conduct a jurisdictional scan to review how other natural gas utilities present energy comparison data in their marketing materials and identify best practices. The Company will use this

information to determine if further changes should be made, and will consider if additional energy technologies, such as, but not limited to, electric ccASHPs, should be added.

Original attachment package

in market April 2023

Choose to pay less for energy

Save by switching to safe, reliable natural gas.

~~**Save up to 65% each year**~~
~~by switching to natural gas~~

What's inside:

See how much you can save

5-step guide to get connected

ENBRIDGE®
Life Takes Energy®

Ready to lower your energy bills?

~~Ready to cut energy bills in half?~~

Good news—natural gas is a convenient solution ~~to~~ that could help you save. This package will guide you through everything you need to know and all the benefits of safe, reliable natural gas. ~~about connecting your home or business and all the benefits of affordable, reliable natural gas.~~

Lower energy bills

~~Save up to 65 percent* each year~~

Compared to electricity, propane or oil, switching to natural gas could save you on home and water heating costs year round. It's more convenient: you'll never run out of fuel or wait for trucks to arrive.

Lower carbon emissions

Natural gas is cleaner than other fuels and can help reduce your home's carbon footprint.

It's easy to get started

Follow our simple five-step guide on page six to see how the connection process works.

~~See how much you can save~~

~~Use our online calculator to see how much you can save by switching to natural gas. Enter your home's size, age and a few more details to get a personalized estimate of annual savings.~~

~~Calculate your savings by visiting **enbridgegas.com/savewithgas** and finding your community page to use the calculator.~~

Ahmed Al-Amry

Ahmed Al-Amry
Supervisor, Community Expansion
Enbridge Gas

If you have questions about connecting to natural gas, please contact one of our Community Expansion advisors.

Get in touch any time

~~For construction updates or questions about the steps to connect to natural gas, personalized cost savings and more, contact one of our Community Expansion Advisors.~~

Community Expansion Contacts:

Phone: 1-833-356-2689

Email: ceapplications@enbridge.com

There are many alternatives to serve your energy needs. Visit Natural Resources Canada at tinyurl.com/y3k2nh8b to learn more about alternative technologies such as heat pumps. Please consult your HVAC provider about energy options, building considerations and costs to meet your specific needs.

* Natural gas prices are based on Rate M1 rates in effect as of ~~**April 1, 2023**~~ and include the $0.23 per m^3 expansion surcharge. ~~Oil price is based on the latest available retail price. Electricity rates based on Hydro One Distribution rates (Mid-density R1) as of **Jan. 1, 2023** and Regulated Price Plan (RPP) customers that are on Time-Of-Use (TOU) pricing. They include the new Ontario Electricity Rebate (OER). The propane price comparison is based on the lowest price obtained in an area survey conducted quarterly. Since individual fuel prices vary, savings assumptions may or may not be as accurate in your situation. Please use the savings calculator found on this page for a more accurate savings estimate. Costs have been calculated for the equivalent energy consumed and include all service, delivery and energy charges. Carbon price is included for all energy types as reported. HST is not included.~~

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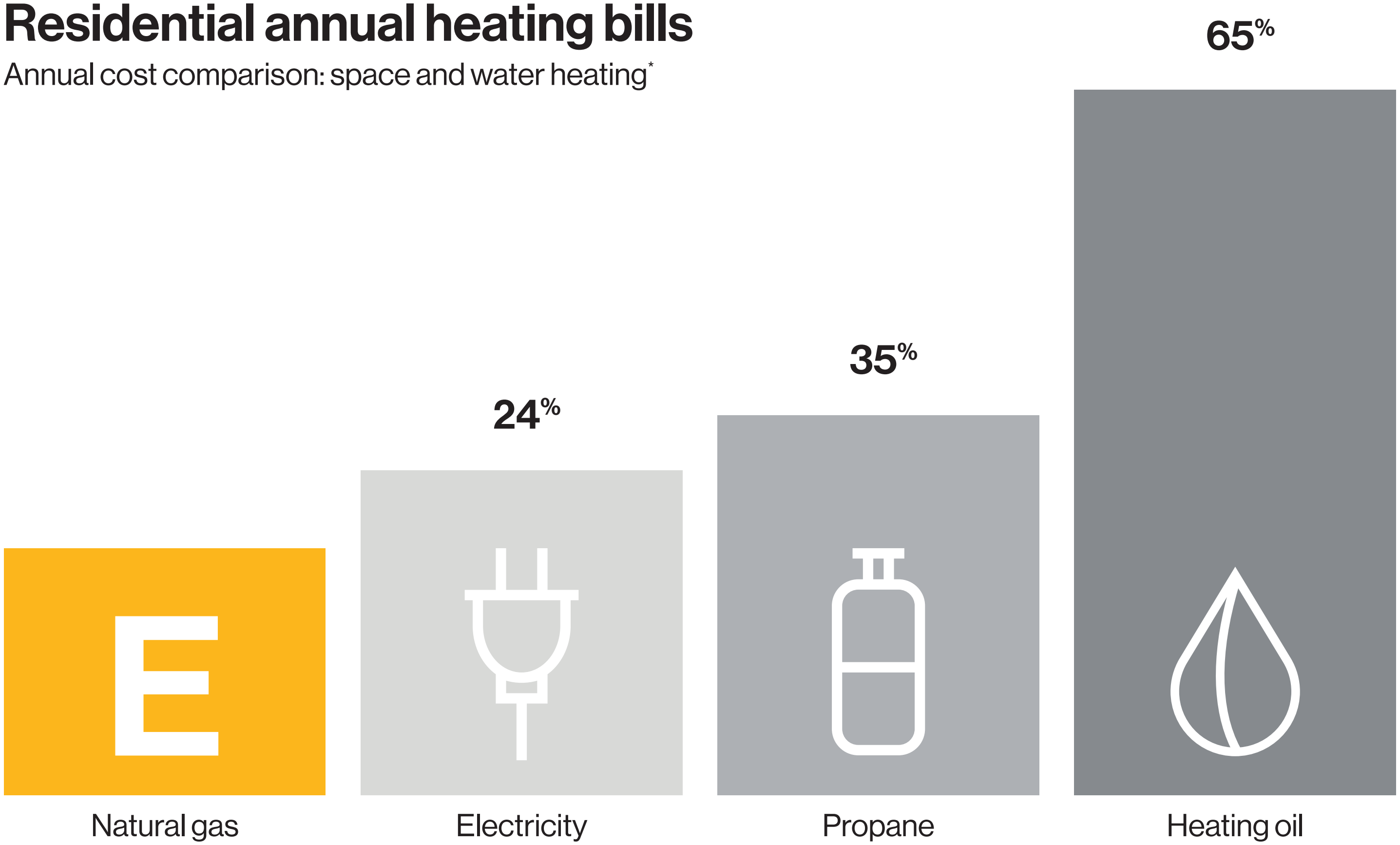
Cost and benefits

How much can you save each year?

Lower costs, lower emissions, more convenience and peace of mind.

Residential annual heating bills

Annual cost comparison: space and water heating*



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Bring home all the benefits

Cost effective
~~**More affordable**~~

Compared to other fuels and electricity, natural gas is ~~the most cost-effective way~~ a cost-effective way to heat your home and water.

Comfort and convenience

Never worry about running out of fuel or waiting for deliveries again.

Versatile and efficient

From fireplaces to clothes dryers, natural gas can make your home more comfortable and enjoyable.

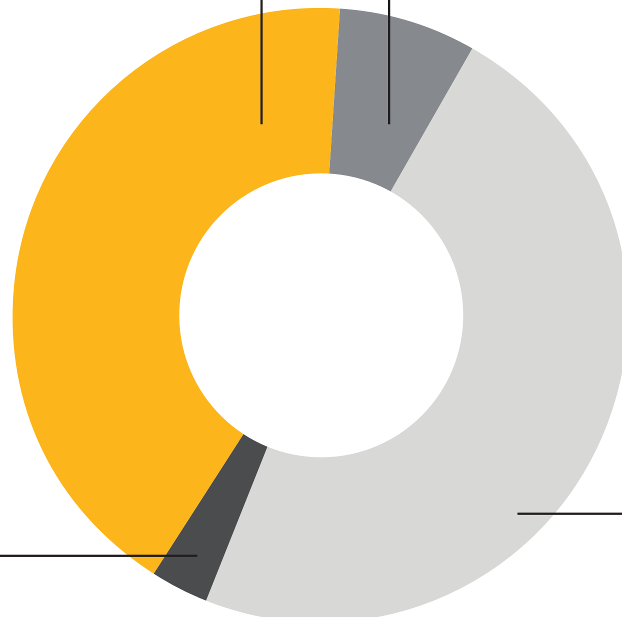
Lower carbon emissions

Natural gas can help reduce your home's carbon footprint.

Where does your money go?

Here's a helpful explanation of a few key items on your natural gas bill

Expansion Surcharge
The fairest way to cover the infrastructure costs of expanding natural gas service.



Customer Charge
This is a fixed $23.98* amount that pays for 24/7 emergency response and other services.

* Subject to change. Please note that all charges, except the fixed customer charge, vary based on how much natural gas you use.

Cost Adjustment
Natural gas rates vary by season—you pay what we pay.

Supply, Delivery and Transportation Charges
These cover the costs to buy and deliver natural gas to your home.

Frequently asked questions

Q: Why do I have to pay an additional charge towards the construction costs of the project?

A: For us to extend natural gas to rural areas where the cost of building the infrastructure is more than the revenue it generates, the Ontario Energy Board approved an additional expansion surcharge. This is a variable rate charge, based on your usage, of $0.23/cubic metre of natural gas used. Since homes use more natural gas in colder months, the surcharge will be higher in winter. It will appear as a separate line item on your monthly bill for up to 40 years.

Go to **enbridgegas.com/savewithgas** to get an estimate of your potential fuel savings.

Q: Why is the surcharge in effect for different lengths of time by community?

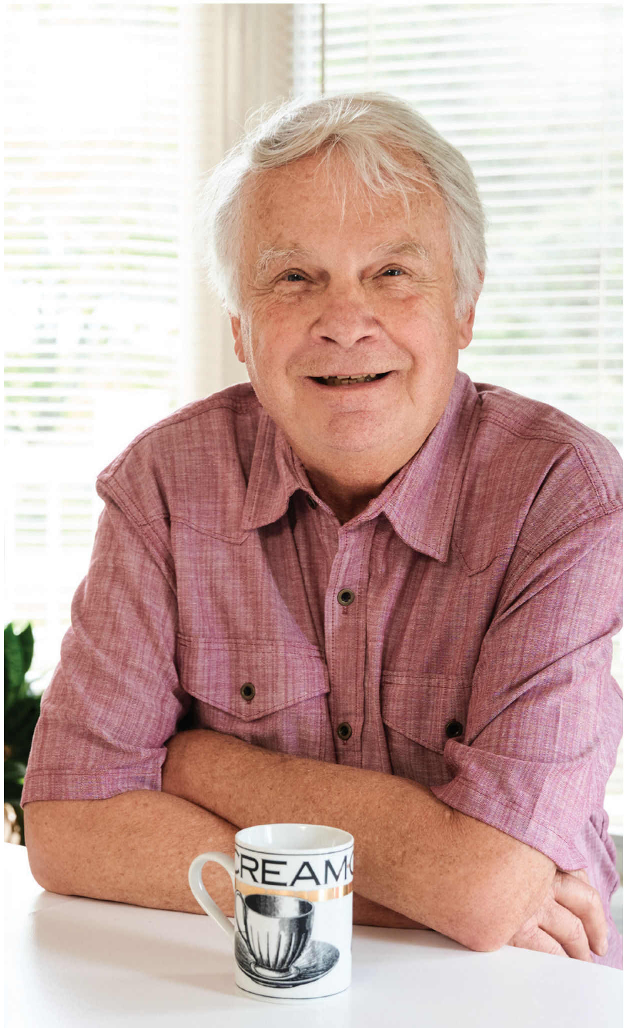
A: The length of time the surcharge remains in effect varies by community because the overall cost to serve each community is different, based on factors such as the distance of the community from an existing natural gas pipeline and more.

"~~We've saved all kinds of money by converting to natural gas, especially over the cost of hydro these days. It just made sense.~~"

~~– Phil Dewsnap, Homeowner, Fenelon Falls~~

"~~I live in a rural region. That means I have my own septic, my own water, and if things don't work, I'm in real trouble. Natural gas has helped me be more independent and I saved a really good buck.~~"

~~– John Powell, Homeowner, Scugog Island~~



"~~The advice I would give others is to convert to natural gas. We've seen a lot of energy savings, the conversion was simple and you get some extra money in your pocket, so it's worth doing.~~"

~~– Phil Dewsnap, Homeowner, Fenelon Falls~~

5 simple steps to switch

It's always best to complete your application for natural gas service as early as possible. This helps us to ensure you are included in our planning process.

1. Inquire with us

Visit **enbridgegas.com/savewithgas** to review project details, calculate your estimated savings and engage with our project team to answer any of your questions.

2. Get an estimate from your local heating contractor

Once you have made your decision to convert, your contractor will submit the natural gas service application on your behalf. You will receive an email summary of the gas application as submitted by your contractor.

A member of our team will contact you to coordinate locating and marking all existing underground utilities.

3. Acknowledge your account details

You will receive a confirmation email with a verification link prompting you to validate the following: your service address, homeowner and billing information.

You will be provided details on the expansion surcharge, which will fluctuate monthly based on your natural gas use. Even with this surcharge, you can still save significantly every year by switching to natural gas.

4. After we install the natural gas service

Contact your contractor to arrange for the gas meter installation and conversion of your natural gas equipment.

5. The final step

Your new natural gas equipment will be turned on and inspected as required by the Technical Standards and Safety Act.

Natural gas service installation policy

Enbridge Gas will provide and install at no cost, one service line per civic address to new customers which will include up to 30 metres of laid pipe and anything beyond that would be $45 per metre (plus applicable taxes). Call your local heating, ventilation and air conditioning (HVAC) provider for an assessment and to submit an application for gas service.

IMPORTANT!

Do not disconnect your existing fuel source or remove any equipment until your new natural gas service and gas meter have been installed.

Take the first step to savings

Let us know you're interested in connecting to natural gas

ENBRIDGE® Life Takes Energy®

Please send the following information to **ceapplications@enbridge.com** and a Community Expansion Advisor will contact you soon.

Name (please print)

Address

Phone number

Email address

Existing Primary Heat Source

Existing Secondary Heat Source

Signature

Date

Completing this Expression of Interest Card is not an application for natural gas, or a binding contract by either you or Enbridge Gas for natural gas service.

Get in touch any time

Prefer postal mail?
Mail your completed expression of interest to us at:

Enbridge Gas
Community Expansion
PO Box 618
Bobcaygeon, ON K0M 1A0

Questions?
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1-833-356-2689
ceapplications@enbridge.com

Revised attachment package

in market October 2023

Choose to pay less for energy

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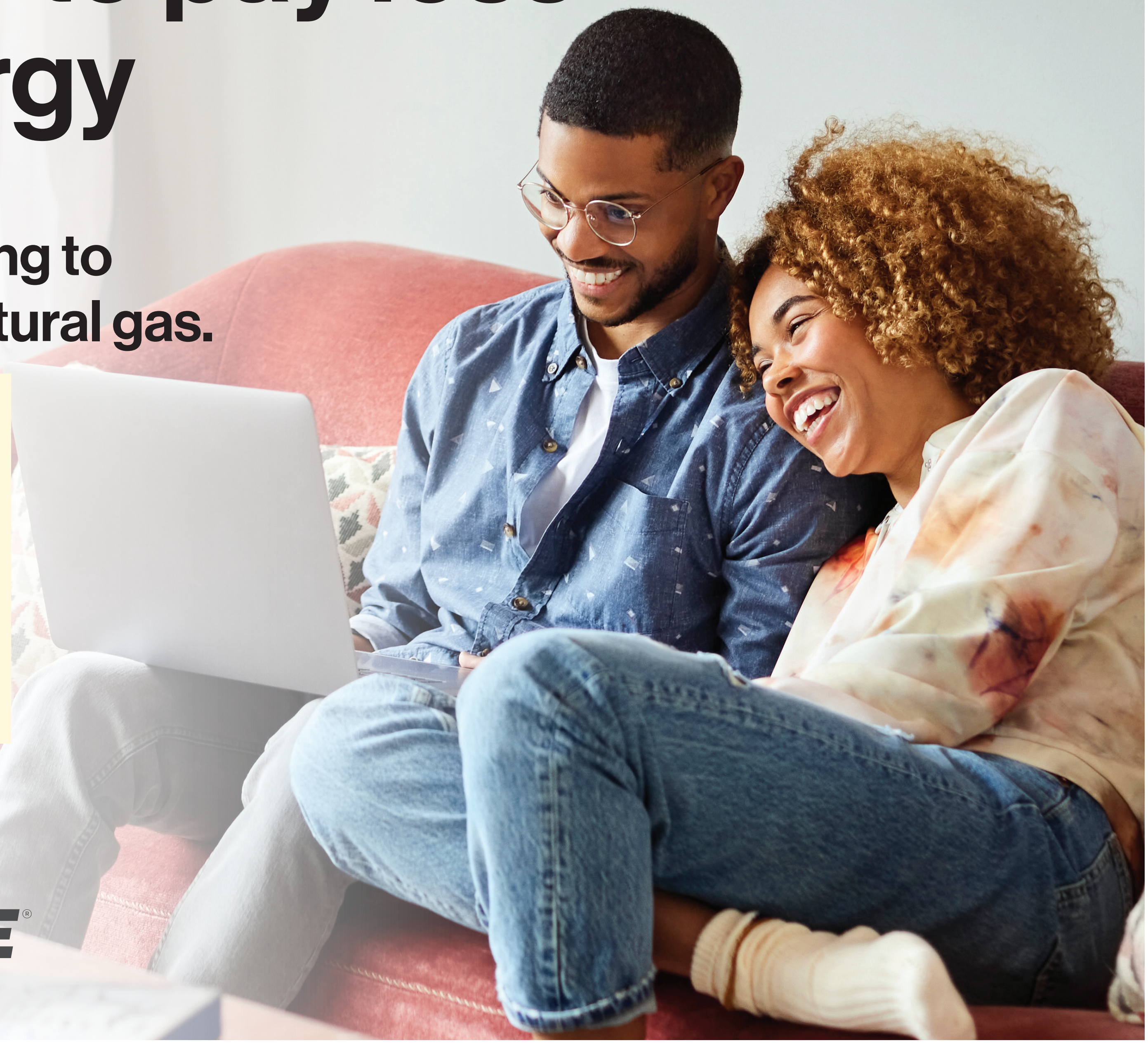

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Ready to lower your energy bills?

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Compared to electricity, propane or oil, switching to natural gas could save you on home and water heating costs year round. It's more convenient: you'll never run out of fuel or wait for trucks to arrive.

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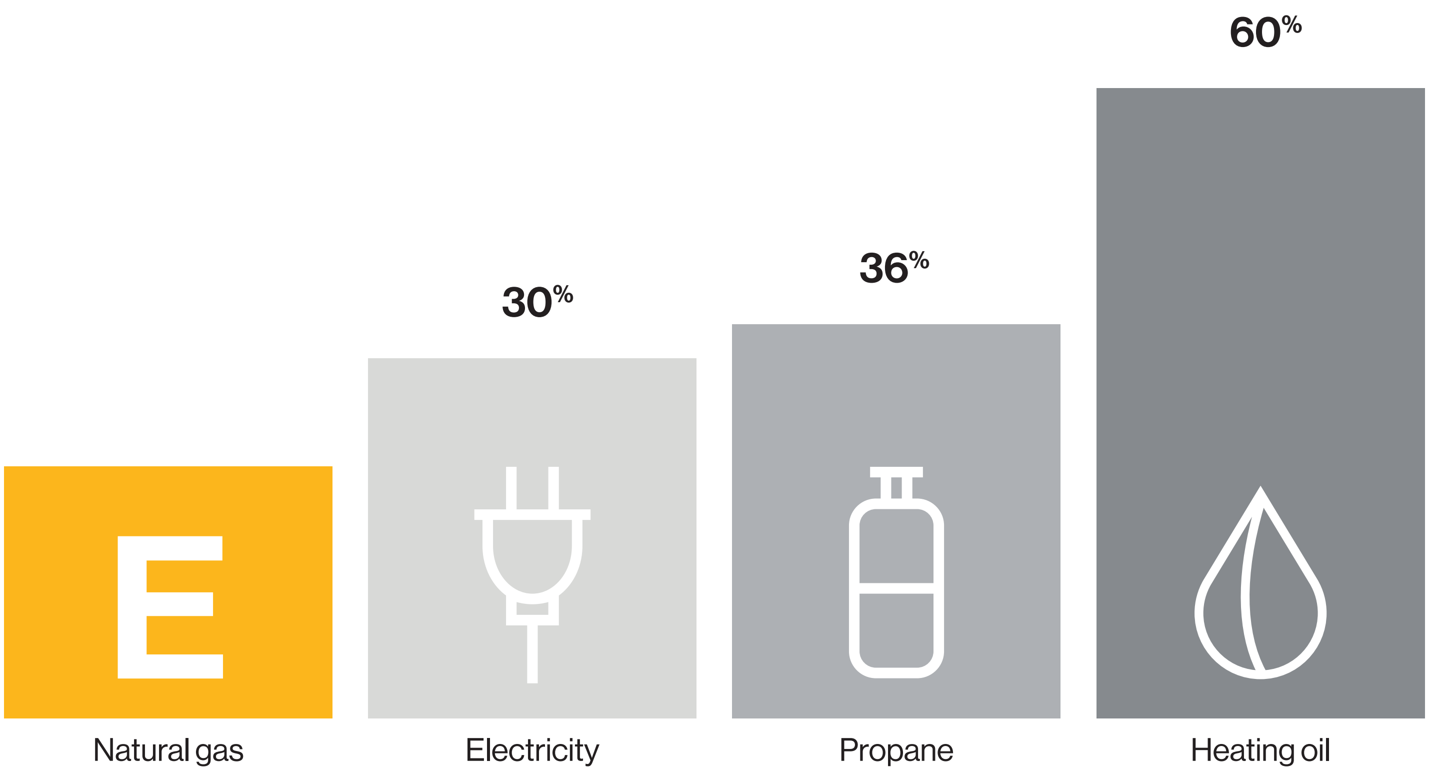

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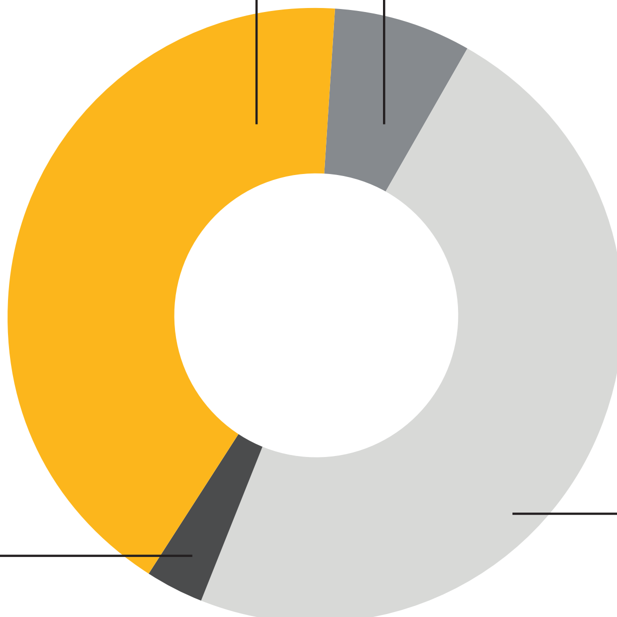

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Programs and rebates to help you save

Enbridge Gas offers a suite of conservation programs to help you save energy at home. From money-saving rebates to discounts and special offers, we're committed to helping you make your home more energy efficient, comfortable and affordable.

Energy conservation is good for you and your community

Reducing energy use is the simplest, most cost-effective way to keep energy costs affordable for everyone. When you make your home more energy efficient, you also help protect it against the effects of a changing climate and contribute to a cleaner, greener Ontario.

Visit our website at **enbridgegas.com/conservation** to find the right program for you.

"I was connected with someone who came to my house and walked through the house with me looking for areas that I could improve on by myself or with professional help. Because of the efforts I've made, it's a lot more comfortable and a lot less cold."

– Erica H.
Program participant
Ottawa, Ontario

How to get connected

5 simple steps to switch

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A member of our team will contact you to coordinate locating and marking all existing underground utilities.

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Address

Phone number

Email address

Existing primary heat source

Existing secondary heat source

Signature

Date

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Enbridge Gas
Community Expansion
PO Box 618
Bobcaygeon, ON K0M 1A0

Questions?
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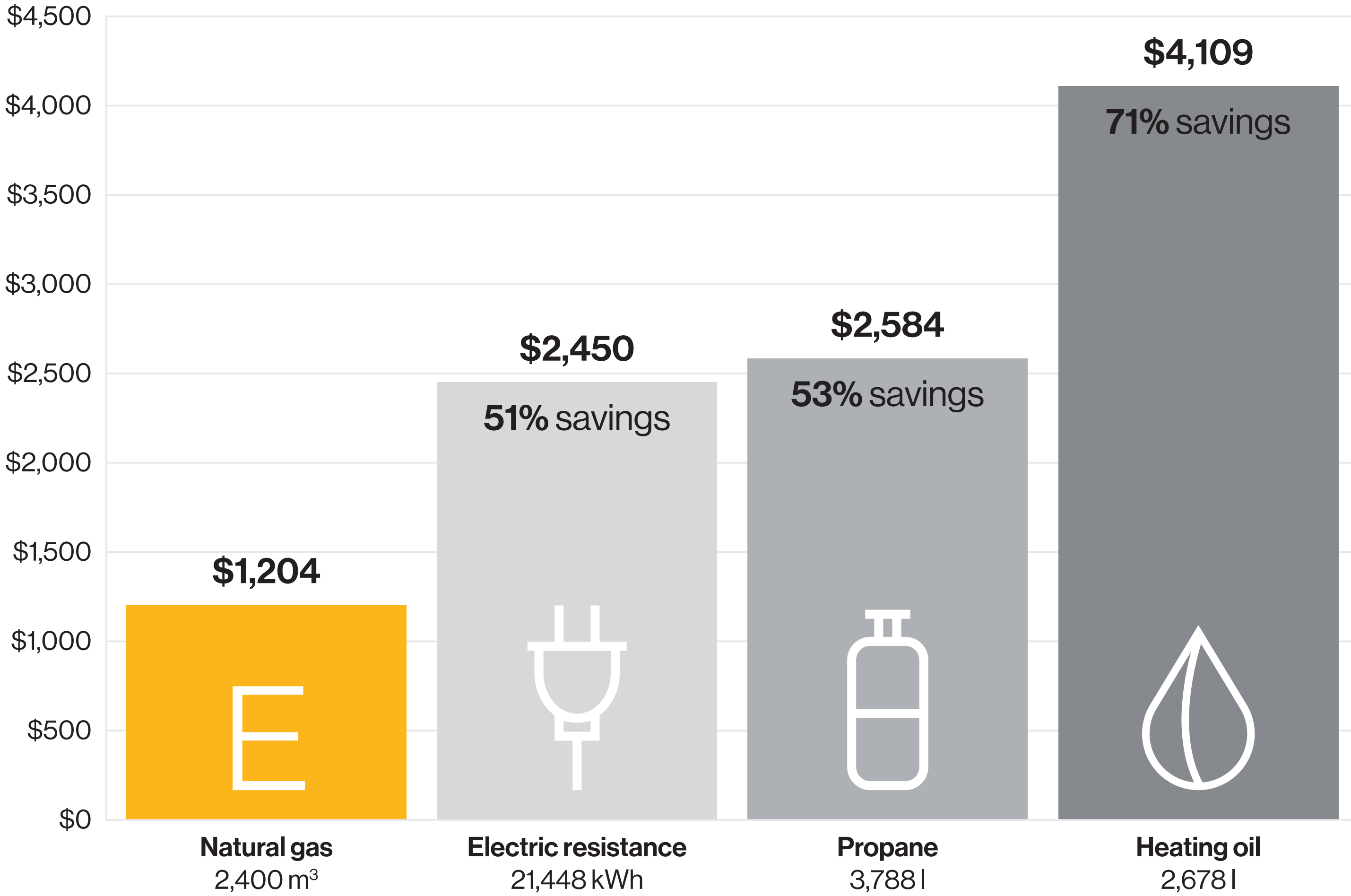
ceapplications@enbridge.com

Estimated annual heating bills for typical residential customer (Rate 1)



Disclaimer:

1. Calculations are based on an estimated 2,400 m³ typical consumption for a residential customer (Rate 1). The term ‘typical’ implies a representative annual consumption. Resulting savings are for illustration purposes only. Consumption levels and savings will vary based on customer region or zone of residence, appliance, appliance efficiency and household characteristics, lifestyle, and energy prices. Please refer to your actual utility bills for specific actual usage, pricing and totals.
2. Natural gas price is based on Rate 1 rates in effect as of April 1, 2024 (EB-2024-0093).
3. Electricity rates based on Toronto Hydro rates as of Jan. 1, 2024, and Regulated Price Plan (RPP) customers that are on Time-Of-Use (TOU) pricing. It includes the Ontario Electricity Rebate (OER) of 19.3%.
4. Heating oil prices sourced from Statistics Canada, CANSIM (v735163), average retail prices for gasoline and fuel oil, by urban centre, Toronto, Ontario based on the latest actual data available at the time of comparison.
5. Propane prices sourced from EDPRO website (edproenergy.com/residential/) and assumes pricing for Zone 5 (2,500 – 4,499 litres) based on the average of the daily prices of the latest calendar month available at the time of comparison.
6. Costs have been calculated for the energy-equivalent annual consumption adjusted by efficiency factors and illustrate an estimated energy-equivalent annual heating bill for conversions from electric resistance, heating oil, and propane to natural gas.
7. Initial upfront costs/setup costs are not included in the energy comparison calculations.
8. Typical consumption for a residential customer is comprised of both heat load and base load. Energy comparison assumes space heating for heat load and water heating for base load.
9. The federal carbon charge is included for all applicable energy types as reported and expected to increase annually depending on government policies. Effective Nov. 9, 2023, the federal carbon charge has been paused for a 3-year period on heating oil used exclusively for home/building heating.
10. HST is excluded from all energy types.
11. Non-natural gas alternatives such as electric cold climate air source heat pumps (ccASHP) are not included in the energy comparison. Please consult an HVAC service provider regarding specific energy options, building considerations, cost estimates appropriate to your specific needs, and electric-related costs.

ASSET LIFE EXTENSION AND SYSTEM PRUNING

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1. In its Phase 1 Decision and Order,[1] the OEB suggested that Phase 2 would provide an opportunity to examine:
   a) How Enbridge Gas can address the stranded asset risk associated with system renewal investments, by taking into consideration economic alternatives to gas infrastructure replacement projects, such as exploring asset life extension (ALE) and system pruning;
   b) How the costs of these economic alternatives can be treated for rate making purposes, either expensed or capitalized, and how these costs should be recovered; and,
   c) Ways in which Enbridge Gas could be provided with an incentive to implement these economic alternatives.

2. The purpose of this evidence is to present Enbridge Gas's response to the OEB's comments and directions from the Phase 1 Decision.

3. In relation to ALE, Enbridge Gas explains its proposed approach, including the treatment of new costs. The Company requests that the OEB approve the proposed modified approach for incremental capital module (ICM) treatment for ALE capital projects. The ALE scope is expected to be initially focused on Enhanced Distribution Integrity Management Program (EDIMP) projects; however, with

[1] EB-2022-0200, Decision and Order, December 21, 2023, p.52.

increased data collection and program maturity, this could evolve.

4. In relation to system pruning, Enbridge Gas explains some of the challenges, and its plan to work with the Integrated Resource Planning Technical Working Group (IRP TWG) to develop a pilot project. Enbridge Gas believes its system pruning approach will provide the opportunity to begin considering a role for system pruning as part of its Integrated Resource Planning (IRP) activities, with input from stakeholders. At this point in time the concept of system pruning is nascent. Enbridge Gas's system pruning approach has been developed in the absence of any legislative direction, codes, or articulation of government policy on co-ordinated gas and electricity planning. Consequently, the approach to system pruning will have to remain flexible, consider the perspectives of electricity participants and accommodate any future direction from the government, the OEB and safety regulatory authorities.

5. This evidence is organized as follows:
    1. Asset Life Extension Proposal
    2. System Pruning Approach

1. Asset Life Extension Proposal

1.1 Overview of Existing Integrity Management Program

6. Enbridge Gas uses an Integrated Management System (IMS) that outlines high-level management expectations across the organization to support the planning, execution, and oversight of the Company's top priorities: safety and reliability. The IMS uses systematic management processes to manage risk and assure the safety, reliability, and compliance of assets, employees, the public and the environment. To meet the established objectives, the IMS uses ten management programs, including the Integrity Management Program (IMP).

7. Enbridge Gas has a well-documented and well-established IMP, which has the objective of ensuring the Company's assets are fit for service and operated in a safe, reliable, and compliant manner. The IMP is designed to follow applicable technical regulator requirements which include the *Technical Standards and Safety Act (TSSA), O. Reg. 210/01* (under the TSSA) and Canadian Energy Regulator technical regulations. To meet these objectives and technical requirements, the Enbridge Gas IMP consists of five Integrity subprograms (Transmission, Distribution, Facilities, Storage Downhole, and Utilization) and is supported by operational controls. As part of the Integrity subprograms, the Company collects data and information via various programs, standards, operational controls, processes, and procedures to identify known and potential hazards. These hazards are then analyzed and assessed to determine the condition of the applicable asset(s) in support of risk management. This analysis, coupled with risk assessments (using risk-based methodologies) helps to develop asset specific or asset group integrity plans. These plans provide recommendations regarding the proactive mitigation activities required to support Asset Management, which ensures the maintenance of safety and reliability of the Company's assets. These activities also extend the lives of these assets.

8. Commencing in 2024, the EDIMP is a newly established part of the Distribution Integrity Management Program (DIMP) subprogram. EDIMP expands the condition monitoring of operationally critical, higher stress (i.e., 20% to 30% of pipeline Specified Minimum Yield Strength) steel distribution pipelines. Based on initial risk modeling of the DIMP system, EDIMP pipelines account for approximately 7,000 km of approximately 32,000 km of steel pipelines within DIMP. This number will be refined as more information and field validation are obtained as part of the EDIMP Program that was launched in 2024.

9. Initially, EDIMP pipelines will be the focus for ALE considerations. As described in more detail below, some of these pipelines have been included in the Asset Management Plan for replacement. With the evolution of new technologies (e.g., robotic crawler inline inspection (ILI) tools, high-resolution leak detection) and computation methods, there is now an opportunity to obtain more comprehensive and thorough condition data for these pipelines. EDIMP will enable this and will use the data to assess the integrity condition and include a more refined analysis of multiple alternatives to pipe replacement, including continued monitoring and scheduled targeted repairs to extend the life of the asset.

10. As part of the EDIMP work, ILI technology will be used, where possible, to detect potential pipeline defects. Reported features of interest will be inspected in the field through non-destructive examination (NDE) to validate the accuracy of the ILI tool and further interpret the potential impact of other reported features by the ILI. ILIs will be completed on a representative sample of the entire identified higher priority distribution pipeline assets, with the condition results on inspected portions of pipe extrapolated to uninspected portions with similar characteristics (e.g., installation date, diameter, soil conditions, corrosion area, etc.). This data, along with existing condition monitoring and additional survey work, will provide the information to support incremental integrity and risk assessments as well as the formulation of mitigation strategies. The EDIMP approach is similar to what is currently employed by Enbridge Gas for transmission pipeline assets.

1.2 Replacement versus Asset Life Extension Considerations

11. The replacement versus ALE evaluation and determination must consider the benefits and risks of each option, including:

Pipe Replacement

a) Large Capital Investment – Typically has the benefit of resulting in the most significant asset risk reduction but also often requires the largest initial capital investment.
b) Stranded Asset Risk – The risk that the replacement asset may become stranded, which would impact customers (e.g., if the depreciable life of the new asset extends beyond the period of time that the asset is required to supply energy).

Asset Life Extension

a) Cost Effectiveness and Timing – In some cases, where integrity and risk targets are met, the integrity results may support extending the asset life at a more favourable cost than full replacement. Furthermore, this could offer the opportunity to spread costs over many years in comparison to large capital replacements in a single year.
b) Future Capital Investment – Risk that the demand for the energy source provided by the asset outlasts the asset's safe operation, meaning that in addition to the ALE investments made, a future pipe replacement and the associated capital investment could also be required, and likely then at an increased cost.
c) Risk of Uncertainty (Assumptions) – Decisions typically require assumptions and predictive analytics to derive both the condition of the asset and the future repairs that will be required. The accuracy of these predictions come with inherent uncertainty with increasing time horizons.
d) Risk of Uncertainty (Technology Limitations) – Decisions rely on assumptions that a pipeline can be suitably inspected and accurately assessed over a period of time, and these assumptions come with risk and limitations. For instance, inspection technology may be subject to limitations,

both with regards to its accuracy of defect detection and sizing and its ability to inline inspect vintage distribution mains not originally designed for such purposes. Another example is the inability of existing tools to detect certain types of threats in pipelines not designed to be inline inspected. These risks and limitations could impact the original economic assessment and result in a less significant asset risk reduction.

e) Stranded Asset Risk – Life extensions can also have a stranded asset risk where the required investment could result in an asset life that is extended beyond that required to supply energy.

12. Prior to the introduction of EDIMP, limited asset condition data was available on distribution pipelines. Since these pipelines have not traditionally been inline inspected, condition data is limited to operating history and opportunistic observations. In the past, the Company relied on various operating factors to identify pipelines requiring mitigation, including leak history, corrosion protection history, depth of cover issues, and operational experience evaluating pipe condition during maintenance and construction activities (e.g., visible corrosion, coating failures at service connections, weldability issues due to laminations). Alternatives to pipe replacement have been considered in past decision making; however, in the absence of extensive ILI and NDE data, this has typically been completed through mostly qualitative risk reviews, without the rigour that is described in the following sections.

1.3 Asset Life Extension Proposal

13. In response to the OEB direction in the Phase 1 Decision, Enbridge Gas is proposing to implement a new ALE approach as part of the EDIMP Program. This approach will build upon the Company's existing Integrity programs to evaluate and identify ALE alternatives. By completing these additional assessments, Enbridge

Gas will further ensure that the most cost-effective methods are proposed while maintaining appropriate levels of risk and reliability for distribution assets.

14. The core component of EDIMP, as described above, targets condition assessments of higher priority distribution pipelines annually. Following data collection and evaluation, additional effort will be required to assess risks on this subset of distribution pipelines. A risk evaluation will be completed using information collected (including through ILI, operating history, and other surveys) to complement the analysis of the potential threat likelihood and consequences. Calculated risk and reliability results from the risk assessment will be evaluated against established industry and Company standards and thresholds (e.g., health and safety, operational reliability, and financial) to determine if mitigation actions are required, and the relative urgency of such actions to reduce risk to a tolerable level. This type of risk analysis requires incremental work, as it has not previously been used to evaluate distribution pipelines. This analysis may also require additional field validation and information gathering activities to support meaningful conclusions.

15. As part of the new more in-depth approach to assessing integrity related alternatives to replacement, Enbridge Gas will incorporate energy transition sensitivity analysis, which will examine how long the pipeline is expected to be needed under different energy transition scenarios, and additional statistical modelling of residual risk for repair alternatives. This would ensure that all relevant factors, including safety, reliability, risk of stranded assets and cost, are thoroughly considered when determining the appropriate mitigation approach, whether that results in full replacement of gas infrastructure or targeted repairs of assets to extend the useful life or a combination.

16. If mitigation actions are required, the feasible alternatives (e.g., replacement, ALE) will be evaluated through the new ALE assessment that considers risk reduction, stranded asset risk, and cost impacts over various time horizons. The outcome of the ALE analysis will be a recommended set of actions. This type of ALE analysis is incremental to what has previously been done to evaluate distribution system renewal alternatives.

1.4 Asset Life Extension Related Costs

Base Integrity Spend

17. The costs related to current activities used by Enbridge Gas to identify and assess asset risk, as well as how the Company currently evaluates replacement and ALE alternatives are recovered in rates and variances in those costs are recorded in the DIMP Variance Account. Non-capital costs for activity related to the new ALE assessment including identification, analysis and implementation will also be recorded in the DIMP Variance Account, which allows for recovery of amounts related to these activities above the amount embedded in rates.

Additional Resource Requirements

18. Additional resources will be required to support the new ALE analysis and associated incremental activities (risk evaluation and assessment) described above. Recent experience with the newly established EDIMP, via the St. Laurent Replacement Project, has helped identify the level of resources required to complete the incremental tasks listed below. Enbridge Gas has provided its current estimation of the number of FTEs and incremental work required below, subject to further refinement as Enbridge Gas initiates the incremental analysis.
    a) Risk Assessment: The detailed risk assessment completed for each EDIMP pipeline will compile all available condition data to produce pipeline reliability results with consideration of corrosion, third-party damage, manufacturing

defects, equipment failure, and other defects. The combined reliability results for the pipeline will be compared with industry targets (e.g., CSA Z662 Annex O) to determine if mitigation actions must be implemented.

b) Integrity and Risk Computation and Validation Support: Consultants will be used where additional integrity or risk expertise is required to assist in the initial analysis of alternatives or to validate work completed by the Company.
c) ALE Analysis: The ALE analysis of all feasible alternatives will incorporate the financial benefit of risk reductions in comparison to the cost to implement the mitigation actions. The key part of this task includes evaluating and comparing the outcomes of the analysis to determine the preferred solution considering sensitivity to assumptions and the appropriate time horizon for the most likely need for the pipeline.
d) Feasibility Evaluation and Cost Estimates for Mitigations and Replacements: Significant effort is required in the Capital Development & Delivery / Engineering Construction groups to evaluate multiple field locations along the length of the pipeline for the purpose of determining the feasibility and cost of work required as part of the ALE and replacement alternatives. These reviews will focus on constructability items, such as working space required, traffic impacts, and potential environmental impacts which could impact the cost and ability to complete the work.

19. Table 1 summarizes the required incremental labour resources.

Table 1

Required Labour Resources*

Department	Resource (FTEs)	Task
Integrity	Risk Engineer (3)	Risk Assessment (QRA)
Integrity	Consultant	Integrity and Risk Computation and Validation Support
Integrity	Technical Manager (1)	ALE Analysis / Regulatory Support
Finance	Sr. Advisor (2)	ALE Analysis (Including Net Present Value and Energy Transition Impacts)
Regulatory Strategy and Analysis	Sr. Advisor (1)	ALE Analysis / Regulatory Support
Distribution Optimization Engineering	Advisor (0.5)	Gas System Modelling of ALE Alternatives
Capital Development & Delivery / Engineering Construction	Advisor (1)	Feasibility Evaluation and Cost Estimates for Mitigations and Replacements

*The resource list above is a preliminary estimate of impacts. Other groups may also be impacted as the ALE process for EDIMP pipelines evolves.

20. As described below, Enbridge Gas will record the O&M costs associated with the inclusion of ALE analysis activities in the DIMP Variance Account.

Asset Life Extension Project Implementation Costs

21. Where an ALE analysis identifies the most suitable alternative to mitigate an asset risk, the Company will be required to implement mitigation actions to maintain safe operation and to ensure that the residual asset risk remaining post-mitigation can meet established tolerable risk and reliability thresholds. The implementation of an ALE alternative could result in costs that are in excess of what is currently included within the annual base Integrity Capital or O&M spend. Examples of possible ALE alternative actions required to extend the life of an asset include:
    a) O&M
        i. Additional cyclical ILIs to monitor changes in asset conditions;
        ii. Direct assessment excavations to opportunistically validate asset conditions;

iii. Increased frequency of monitoring activities (e.g., leak survey, patrols for third-party excavation work);
iv. Advanced third-party modelling of certain features, such as finite element analysis; and
v. Actions to implement a pressure reduction on the pipeline system to meet risk and reliability thresholds.

b) Capital

i. Significant pipeline repairs to address identified defects;
ii. Partial targeted replacement of short sections of a larger pipeline system; and
iii. Additional measures to reduce third-party damage risk (e.g., installation of physical protection).

22. The extent to which the above ALE implementation activities and associated costs are required will be determined based on a situational assessment of pipeline risk and may differ for each pipeline that is evaluated.

1.5 Asset Life Extension Cost Recovery Proposal

23. This section of evidence focuses on Enbridge Gas's proposal for cost recovery related to ALE activities and costs. This proposal considers the Phase 1 Settlement Agreement and the Phase 1 Decision.

24. As discussed in prior sections of this Exhibit, Enbridge Gas currently performs ALE work as part of its day-to-day operations, and also includes ALE alternatives, where possible, in its analysis of options to mitigate an asset risk. This work is recovered in rates. However, the additional ALE work that Enbridge Gas is proposing to undertake through the EDIMP could result in additional ALE projects that would

impact the timing, type and magnitude of annual O&M and capital expenditures.

25. The 10-year Asset Management Plan currently includes the replacement of three pipelines,[2] totalling $157 million in capital (not including overheads or dismantlement) over the next seven years, that will be subject to EDIMP asset condition data collection in 2024 and 2025. Following the data collection, each of these three pipelines will be assessed and evaluated for a potential ALE rather than full replacement, unless a full replacement is warranted. As described above, any ALE alternatives deemed to be feasible (i.e., lowest cost option meeting risk targets) will require a level of ongoing risk monitoring and assessment and potential further investment (e.g., partial pipe replacements, future ILIs and anomaly repairs) over the useful life of the asset. The ALE alternative costs, however, are anticipated to be lower than the total asset replacement costs and could spread investments over several years in comparison to large capital replacement costs in one year.

26. In future years, this same approach will be used for other high-priority EDIMP pipelines not currently projected for replacement in the AMP. This approach will attempt to extend asset life using targeted analyses and remediations to minimize or potentially eliminate significant replacement costs.

27. Consistent with the Phase 1 Settlement Agreement, Enbridge Gas intends to record O&M costs related to ALE analysis (including the incremental support costs described above) and alternatives in the DIMP Variance Account. The DIMP Variance Account records the variance between the actual DIMP and EDIMP costs and the DIMP and EDIMP costs included in rates ($12.5 million in 2024).[3] This

[2] The three pipelines include Martin Grove, Port Stanley, and Wilson Ave., as detailed in EB-2022-0200, Exhibit 2, Tab 6, Schedule 2, Appendix A, pp.60-61, updated 2023-07-06.
[3] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 2, Accounting Orders – Phase 1, August 17, 2023, p.44.

account was approved by the OEB in the Phase 1 Settlement Agreement.

28. Enbridge Gas proposes that capital expenditures related to ALE alternatives be eligible for recovery via the ICM. To incent Enbridge Gas to pursue additional ALE alternatives, in addition to the ALE work already being performed, Enbridge Gas proposes that ICM eligibility for these projects be determined in the same manner as any other proposed ICM project, with two adjustments. This proposed approach is set out below.

29. In order for capital projects to be eligible for ICM recovery, the current ICM framework requires that a capital project meet the following criteria: materiality, need and prudence. These criteria are set out in Section 4.1.5 of the 'Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, EB-2014-0219'.

30. Materiality is determined through a materiality threshold test wherein

> A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor: otherwise, they should be dealt with at rebasing.[4]

31. Need is determined through a Means Test and ICM funding requests must be based on discrete, material projects.

[4] EB-2014-0219 Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.17.

32. A distributor must pass a means test in order to be eligible for ICM funding. If a distributor's regulated return in its most recent calculation exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, the funding of any incremental capital project will not be allowed.[5]

33. ICM funding requests must be based on discrete, material projects. ICM funding amounts "must be based on discrete projects and should be directly related to the claimed driver. This amount must be clearly outside of the base upon which the rates were derived."[6] In addition, per the MAADs Decision, any individual project for which ICM funding is sought (by Enbridge Gas) must have an in-service capital addition of at least $10 million.[7]

34. With regards to prudence, a distributor must demonstrate "that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers."[8]

35. Enbridge Gas's proposal for an ICM as part of the proposed Price Cap IR plan is detailed at Phase 2 Exhibit 10, Tab 1, Schedule 1. The proposal set out in that Exhibit is largely consistent with OEB established policies for ICM. Enbridge Gas is proposing that the criteria to determine ICM eligibility (materiality, need and prudence) not change with the exception of how these criteria apply to ALE alternatives resulting from EDIMP.

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[5] EB-2014-0219 Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, pp.15.
[6] Ibid, p.17.
[7] EB-2017-0306/EB2017-0307, Decision and Order, August 30, 2018, pp.32-33.
[8] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.17.

36. With respect to ALE alternatives for which ICM treatment is requested, Enbridge Gas proposes that the need criteria be modified to exclude the requirement that a project be discrete and that a project will have an in-service capital addition of at least $10 million. Rather, for ALE alternatives, Enbridge Gas proposes that it be allowed to "group" ALE alternatives together for the purpose of requesting ICM treatment. Further, Enbridge Gas proposes that the in-service capital addition threshold does not apply (i.e., it should be zero dollars) when requesting ICM treatment for ALE alternatives. Other ICM eligibility criteria would remain as is in respect of ALE alternatives.

37. Grouping will allow Enbridge Gas to pursue multiple, smaller ALE alternatives in a single ICM request in years where Enbridge Gas's capital budget exceeds the materiality threshold. This would also reduce the number of ICM requests in a given year should they occur.

38. Grouping will combine similar ALE alternatives under a single ICM request (if the potential for an ICM request is triggered). For example, if ALE analysis is completed on three distribution networks – one in Ottawa, one in Toronto, one in London – and it is determined that pressure containment sleeves are an appropriate ALE alternative in each instance, an ICM request would be made for the total combined capital cost of implementing those ALE alternatives. The ICM request would be comprised of a programmatic capital expenditure amount on containment sleeves for a particular year. Replacement of shorter segments of pipe, rather than a full pipe replacement is another example. To the extent that ALE analysis determines that several small pipe cut outs and replacements across the distribution system are appropriate, those individual pipe cut outs and replacements would be grouped together under a single ICM request for a given year. Grouping could also comprise multiple projects with similar, but multiple ALE alternatives for each. Several smaller

projects each requiring similar work to mitigate identified risks, such as replacement of shorter segments of pipe combined with cathodic protection enhancements for each project would be another example.

39. When determining the maximum eligible capital amount (the difference between the in-service capital forecast in a given year and the materiality threshold for a given year), Enbridge Gas will include ALE alternatives in the determination of the in-service capital forecast. ALE alternatives will form part of the Asset Management Plan, instead of pipeline replacements where an ALE alternative is determined to be appropriate. Consequently, the maximum eligible capital amount will be reflective of Enbridge Gas's capital requirements inclusive of ALE alternatives (rather than pipeline replacements).

40. This approach benefits customers and incents Enbridge Gas to pursue additional ALE alternatives. Customers benefit through lower capital expenditures in the near-term (as replacement may still be required in the future depending on energy transition and demand for natural gas and condition of the asset) which results in lower costs recovered in rates. Under ALE alternatives, customers may also benefit through potentially lower stranded asset risk and lower lifetime costs of an asset.

41. Enbridge Gas believes this approach addresses the OEB's suggestion that Phase 2 of this proceeding provide the opportunity to examine ways in which Enbridge Gas could be incented to implement economic alternatives to gas infrastructure replacement projects, including ALEs. Enbridge Gas interprets the Phase 1 Decision to indicate the OEB's expectation that more ALE alternatives be employed where possible in an uncertain energy transition environment. Enbridge Gas's proposed approach for implementing ALE alternatives will ensure that O&M and capital dollars are deployed efficiently. This will also reduce stranded asset risk.

While traditional incentives for a regulated utility typically involve the opportunity to earn more than would otherwise be the case, Enbridge Gas's proposal for ALE alternatives does not dis-incent the Company from pursuing these types of projects. Rather, this ALE proposal allows for the status quo: recovery of O&M and capital costs and the ability to earn a return on capital dollars invested.

42. Enbridge Gas believes this approach will allow for additional ALE alternatives to be implemented. ALE alternatives that result in O&M expenditures will be recorded in the DIMP Variance Account (in addition to the O&M costs associated with ALE analysis, risk evaluation and assessment). ALE alternatives for which capital expenditures are required would be accommodated within Enbridge Gas's capital budget in a given year, to the extent that the capital budget does not exceed the ICM materiality threshold. To the extent that an ALE alternative(s) cannot be accommodated within the capital budget below the ICM materiality threshold in a given year, it will be possible to seek recovery of the ALE alternative capital costs via the ICM framework (as applied to ALE alternatives pursuant to this proposal). This proposal will also tend to flatten the future capital expenditure profile as large replacement projects are substituted for smaller ALE alternatives.

2. <u>System Pruning Approach</u>

43. In the Phase 1 Decision, the OEB pointed to system pruning as a way to reduce system renewal expenditures, giving the example of "converting a subdivision from gas to electricity for space and water heating".[9] The OEB positioned system pruning as an IRP approach. In the sections below, Enbridge Gas sets out how it proposes to consider system pruning.

[9] EB-2022-0200, Decision and Order, December 21, 2023, p.52.

44. As explained in this evidence, this initiative will be challenging and should start with consultation and engagement with the IRP TWG.

45. Enbridge Gas's approach to system pruning, which is further described in the sections below, is to work with the IRP TWG to consult on system pruning processes and what role the Company could play in a system pruning pilot. The system pruning work with the IRP TWG will be informed by the government's forthcoming policy statement on the role of natural gas. Enbridge Gas anticipates that future policies on co-ordinated energy system (gas and electric) planning will be important to informing system pruning activities because it is anticipated that it will support discussions about available electric system capacity and capacity constraints, information flow that would be necessary to assess the economic feasibility of an electric alternative, and how to optimize both energy systems while continuing to maintain customer choice.

46. Enbridge Gas notes that customer choice is an important consideration, and that the current statutory and regulatory framework does not envisage transitioning customers to a different energy source unless they agree.

2.1. Overview of Current IRP Framework

47. On July 22, 2021, the OEB approved a first-generation IRP Decision and Order, and companion document IRP Framework (collectively referred to as the IRP Decision),[10] to guide Enbridge Gas's consideration of alternatives for the Company's infrastructure investments to defer, avoid or reduce the need for new pipelines and/or upgrades to existing infrastructure.

[10] EB-2020-0091, Decision and Order, Issued July 22, 2021.

48. According to the IRP Decision, when Enbridge Gas determines that an IRP alternative (IRPA) (either alone, in combination with other IRPAs, or in combination with a facility project) is the best option to address a system need, it will apply for approval of an IRP Plan that enables that alternative.[11] The IRP Decision defined the scope of eligible IRPAs[12] to include:
    - Demand-side alternatives – may include geo-targeted energy efficiency and demand response programs designed to target the constrained area by incenting customers to reduce energy consumption during peak demand. A modified interruptible rates design to influence customer demand may also be included as part of an IRP Plan application.
    - Gas supply-side alternatives – may include injection of compressed natural gas, liquid natural gas or renewable natural gas into the constrained area, or market-based supply alternatives including upstream deliveries and natural gas storage.

49. Enbridge Gas submitted a proposal for non-gas alternatives; however, the OEB in its IRP Decision concluded that "as part of this first-generation IRP Framework, the OEB has determined that it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs."[13]

50. During the deferred rebasing term, the IRP Decision established two IRP deferral accounts to track and recover IRPA operating expenses and project costs until the end of 2023.[14] The OEB found that it was appropriate for the first-generation IRP Framework that IRPA project costs be "eligible for inclusion in rate base where Enbridge Gas owns and operates the IRPA" and that "Enbridge Gas should include

[11] EB-2020-0091, Decision and Order, Issued July 22, 2021, p.8.
[12] Ibid, p. 34
[13] Ibid, p.35.
[14] Ibid, p.86.

in the project costs any physical assets acquired and costs directly attributable to the project consistent with how fixed assets are currently capitalized under US GAAP."[15] The IRP Capital Costs Deferral Account records the actual annual revenue requirement of project costs eligible to be capitalized for inclusion in rate base as part of approved IRP Plans (where Enbridge Gas owns and operates the IRPA).[16]

51. The OEB also established the IRP Operating Costs Deferral Account to record incremental IRP general administrative costs, and ongoing O&M evaluation costs, including ongoing enabling payments to service providers where Enbridge Gas does not own or operate the asset.[17] These costs are treated as expenses and not included in rate base.

52. The OEB found that as part of the first-generation IRP Framework that it was "premature to develop an incentive mechanism or offer additional incentives"[18] and that incentives could be explored as part of a future IRP Plan as experience and lessons are gained.

53. Phase 1 of the Rebasing Application included general IRP administrative costs in the 2024 Test Year Forecast. Any IRP Plan related project costs and incremental IRP administrative and operating and maintenance costs for approved IRP plans would continue to be cleared through the appropriate IRP deferral account. In the Phase 1 Settlement Agreement, Enbridge Gas and parties agreed that modifications would be made to the IRP deferral accounts. The IRP deferral accounts will now also record offsetting avoided operating costs and avoided

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[15] EB-2020-0091, Decision and Order, Issued July 22, 2021, p.75.
[16] Ibid, p.87.
[17] Ibid, p.86.
[18] Ibid, p.76.

revenue requirement already included in rates related to facilities that are delayed, avoided, or downsized by an IRP Plan.[19]

54. In the Phase 1 Decision, the OEB raised the concept of using a comprehensive IRP approach to system renewal projects as a mitigation strategy to reduce the risk of stranded assets due to the energy transition.[20] The OEB proposed that Enbridge Gas consider economic alternatives to gas infrastructure replacement projects, including system pruning (i.e., replacement of gas equipment with electric equipment). These economic alternatives to gas infrastructure and the treatment of costs are concepts that were not defined or mandated by the OEB as part of the IRP Decision and, therefore, require further guidance from the OEB. As such, the OEB determined that Phase 2 is the appropriate time to "examine ways in which Enbridge Gas could be provided with an incentive to implement economic alternatives to gas infrastructure",[21] how the costs of these economic alternatives can be treated for rate making purposes, either expensed or capitalized and how these costs should be recovered.[22]

2.2. System Pruning Overview

55. System pruning involves the strategic decommissioning of a portion of the natural gas system that is no longer required to serve the needs of energy users. To proceed with the pruning of a targeted portion of the system, all customers served by that pipeline system must have fully converted off natural gas and be willing to disconnect from the pipeline system.[23]

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[19] EB-2022-0200, Settlement Agreement, Exhibit O1, Tabs 1, Schedule 2, Accounting Orders - Phase 1, August 17, 2023, pp.39-40.
[20] EB-2022-0200, Decision and Order, December 21, 2023, p.52.
[21] Ibid.
[22] Ibid.
[23] Enbridge Gas understands that without statutory and/or regulatory changes or exemptions, the Company can only prune segments of the distribution system where all customers have agreed to disconnect.

56. The OEB noted in the Phase 1 Decision that system pruning could be supported by an IRP solution, which would include supporting existing customers in replacing their gas equipment with electric equipment to avoid the need to replace the facilities.[24] The IRP Program could offer customers incentives to defray the cost of replacing their gas equipment, or investment by the utility to cover the cost of the electric equipment to be recovered over time, with a return on that investment.

57. The Phase 1 Decision also notes that a comprehensive IRP approach to system pruning would include comparing the cost of the system renewal project (i.e., maintenance or replacement of the pipeline) against the cost of the system pruning alternative (i.e., replacing gas equipment with electric equipment). If the system pruning alternative is economically feasible, it would be implemented to defer or eliminate the need for the system renewal project.[25]

58. Enbridge Gas suggests that system pruning will require further analysis to determine the conditions under which it could be an appropriate IRPA; however, system pruning could potentially be technically and economically feasible in some cases where maintenance or replacement of a segment of pipe is needed, and elimination of that segment will have no detrimental impacts on system safety or reliability. In addition to pipeline safety and reliability, factors to be considered include customer interest in electrification and ensuring the electrical grid in the project area can support the incremental demand.

59. Ideal candidates for system pruning (i.e., those that are anticipated to be both technically feasible, cost effective, and have no impact on system safety and reliability) are likely to include segments of the system that require maintenance or

[24] EB-2022-0200, Decision and Order, December 21, 2023, p.52.
[25] Ibid.

replacement, are one-way fed, and have a relatively small number of services attached that feed residential or small commercial customers.

60. Enbridge Gas believes potential non-gas building heating alternatives could include electric heat pumps and thermal networks. In addition to building heating appliances, consideration would also need to be given to electrification of other appliances such as water heaters, stoves, fireplaces, clothes dryers, and pool heaters, as well as upgrades that may be needed to building envelopes, electrical systems, and HVAC systems.

61. For clarity, given the issues put forward by the OEB in the Phase 1 Decision and the OEB's interest in considering electric IRPAs as part of the Pilots Application,[26] it is the Company's understanding that the more recent Phase 1 Decision supersedes the existing decision from the first-generation IRP Framework and signals that piloting electric measures would be an effective way to understand how the IRP Framework could be evolved.

2.3. Development of a System Pruning IRP Pilot

62. The development of an IRP system pruning pilot will require time, as the Company will need to work through a comprehensive proposal, inclusive of coordinated stakeholder engagement.

63. Enbridge Gas will need to develop processes to identify and evaluate segments of the Company's system that are candidates for system pruning. This includes system pruning processes for:

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[26] EB-2022-0335, Procedural Order No.3, November 17, 2023.

- Binary screening, which would be used to rule out parts of the system where removal of the pipeline segment would cause an impact on safety and/or reliability;
- Technical evaluation to ensure a potential project is technically feasible;
- Stakeholder consultation with the Independent Electric System Operator (IESO), the local distribution companies (LDCs) and the local municipalities in areas where potential candidates for system pruning have been identified;
- Economic evaluation to determine if a potential pruning project is economically favourable; and,
- Engaging with the customers attached to the potential candidate pipeline to determine their interest in switching from natural gas to electricity for all of their gas energy uses.

64. Evaluation of technical feasibility could include the review of factors such as, but not limited to:
    - The number of connected services;
    - The types of attached customers (i.e., residential, commercial, industrial);
    - The planned in-service date of the project to allow sufficient pre-planning time; and,
    - The driver of the project need (i.e., urgent issue or monitored issue).

65. While ensuring system pruning does not cause an impact to the gas system from a safety or reliability perspective will be critical, it will also be of utmost importance to ensure that electrification of the customers on a particular segment of pipeline will not cause any negative impact on the electric system, such as electricity supply shortages in an area. This will require knowledge on aspects of the electric system that Enbridge Gas does not possess, and, therefore, coordinated planning will be required between Enbridge Gas and the applicable electric system planners,

including the IESO and the LDCs, as well as with the local municipalities in areas where potential candidates for system pruning have been identified.

66. Recently, the Government of Ontario released a report[27] from the Electrification and Energy Transition Panel (EETP) with recommendations for the energy sector to help Ontario's economy prepare for electrification and the energy transition, and to identify strategic opportunities and planning reforms to support emerging electricity and fuels planning needs. The Panel issued a series of recommendations with Recommendation 16 stating that "The Ministry of Energy, working with the OEB, IESO, LDCs, municipalities and gas utilities, should develop a formal and transparent co-ordination framework that sets out the scope and objectives for enhanced planning and co-ordination at the bulk, regional and distribution levels." [28]

67. Enbridge Gas is currently unaware of the status of this recommendation and has not seen any public communication of any changes to energy system planning to enable enhanced coordination since the EETP Report was issued. While Enbridge Gas looks forward to formal direction from the Ministry of Energy with respect to coordinated planning, to move forward with system pruning related discussions in the absence of a recognized framework or governance structure, Enbridge Gas will require the support and participation of the IESO, the LDCs and local municipalities. in the stakeholder engagement process.

68. System pruning will also require a framework that allows for a consistent comparison of the economic feasibility of gas and electric energy solutions. This framework would consider costs incurred by Enbridge Gas for a system pruning

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[27] Ontario's Clean Energy Opportunity: Report of the Electrification and Energy Transition Panel, December 2023. https://www.ontario.ca/files/2024-02/energy-eetp-ontarios-clean-energy-opportunity-en-2024-02-02.pdf

[28] Ibid, p.97.

project. Further review will be required to determine how electric system costs incurred to support the incremental load coming on to the electric system are considered. Enbridge Gas notes that currently, the cost benefit tests by gas utilities and LDCs are not consistent.[29]

2.4. Proposed Approach to System Pruning

69. Due to the breadth and complexity of factors that are required to develop a system pruning IRP program and the limited amount of time between the Phase 1 Decision and the date of filing the Phase 2 evidence, Enbridge Gas is not submitting a specific system pruning proposal in Phase 2. Enbridge Gas is, instead, proposing to engage the IRP TWG and other relevant stakeholders in a collaborative process to determine if there is a technically and economically feasible system pruning IRP pilot to pursue and, if so, develop, together with the electric sector, a system pruning pilot.

70. The IRP TWG was established with an objective of providing input that is of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework. As IRPAs evolve beyond the first-generation IRP Framework, Enbridge Gas believes it is appropriate to engage with the IRP TWG on any foundational elements that would need to be utilized in an identification of a Pilot. This will include:

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[29] In the IRP Decision the OEB approved the DCF+ test as the economic test for the IRP Framework. The OEB directed Enbridge Gas to "study improvements to the DCF+ test for IRP" in consultation with the IRP Technical Working Group and "file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan." (EB-2020-0091, IRP Decision, p.57). Updates to this process can be found at https://engagewithus.oeb.ca/irp

The OEB released the Non-Wires Solutions Guidelines for Electricity Distributors on March 28, 2024 (EB-2024-0118), which outlines a methodology for electricity distributors to assess the economic feasibility of non-wires solutions.

- The binary screening criteria to identify potential pipeline candidates;
- The methodology to evaluate the technical feasibility of potential pipeline candidates;
- The methodology to evaluate the cost effectiveness to compare alternatives;
- How the costs of proposed economic alternatives should be treated for rate making purposes;
- How these costs should be recovered; and,
- The manner in which Enbridge Gas should be provided with an incentive to implement system pruning.

71. To support the IRP TWG in the identification of a technically and economically feasible system pruning IRP pilot, Enbridge Gas will complete a scan to identify how utilities in other jurisdictions are approaching gas system pruning to identify best practices, where available.

72. In determining the economic feasibility of a system pruning pilot, Enbridge Gas will consider the optimal alternative to meet customer energy needs and engage with the market inclusive of potential associated service provider(s). Outreach with customers on a candidate system will also be required to ensure there is interest in conversion for enrollment.

73. This approach will provide insights into the binary screening criteria, technical feasibility, costs, and benefits of system pruning, while allowing Enbridge Gas to also test coordination of energy system planning and an aligned economic test. It will also provide valuable insights into customers willingness to participate in an electrification program.

GAS SUPPLY, TRANSPORTATION & STORAGE COSTS

AMY MIKHAILA, DIRECTOR GAS SUPPLY

STEVE DANTZER, SUPERVISOR GAS SUPPLY PLANNING

DAVE JANISSE, MANAGER GAS SUPPLY ACQUISITION

1. Enbridge Gas has updated this evidence to reflect the following issues that are being addressed in Phase 2 of this Application.

   18 a) Is the 2024 gas supply cost, including the forecast of gas, transportation, and storage costs, appropriate?

   39) Is the proposed harmonized methodology for determining the amount of storage space and deliverability required to serve in franchise customers appropriate, and is the proposed allocation of storage space and deliverability among customers appropriate?

   49) Is the proposal to add 10 PJ of market-based storage at a cost not currently included in the 2024 Test Year gas cost forecast appropriate?

   51) How should the determinations made for the Phase 2 Storage issues be addressed and implemented, including any required changes to 2024 costs and revenues, the Gas Supply Plan and gas supply deferral and variance accounts?

2. Issue 18, part a) was largely settled as part of the Phase 1 Settlement Agreement[1], with the exception of the determination of load balancing costs (including storage) which was deferred to Phase 2.

3. Enbridge Gas interprets Issue 39 to include both the amount of storage space and deliverability[2] required to serve in-franchise customers and the amount of cost-based storage space and deliverability allocated to in-franchise customers.
   a) The determination of the in-franchise storage space and deliverability requirements are provided in this evidence at Section 1;
   b) The amount of storage deliverability allocated to in-franchise customers is provided at Phase 2 Exhibit 4, Tab 2, Schedule 5; and
   c) The amount of cost-based storage space allocated to in-franchise customers is included in Issue 47 and is provided at Phase 2 Exhibit 4, Tab 2, Schedule 8.

4. Issue 49 addresses the 10 PJ of market-based storage for load balancing purposes that was not included in the Gas Supply Plan for the 2024 Test Year Forecast in Phase 1. As part of the Phase 1 Settlement Agreement[3], parties agreed that Enbridge Gas would maintain the current level of market-based storage until a determination is made as part of Phase 2 of this Application. As part of Phase 2 and provided at Attachment 1, Enbridge Gas has updated the Gas Supply Plan for the 2024 Test Year Forecast to include the cost of the 2024 storage requirement of 227.7 PJ which includes 10 PJ of market-based storage for load balancing.

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[1] EB-2022-0200, Settlement Agreement, August 17, 2023.
[2] The term deliverability is intended to mean firm withdrawal capacity, as referred to in Phase 2 Exhibit 4, Tab 2, Schedule 5.
[3] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p. 35.

5. Enbridge Gas committed to an assessment of its load balancing portfolio including an assessment of the methodology for determining storage requirements. In 2022, ICF Resources, LLC (ICF) conducted an analysis and recommendation for Enbridge Gas's load balancing portfolio (the "2022 ICF Report"). In 2024, ICF provided an update to the 2022 analysis and recommendation based on more recent data and projections (the "2024 ICF Addendum Report"). The 2024 ICF Addendum Report and 2022 ICF Report are provided at Attachment 2 and 3, respectively.

6. Based on the review and recommendation of ICF, Enbridge Gas's 2024 storage requirement of 227.7 PJ includes 10 PJ of storage for load balancing. To meet Enbridge Gas's 2024 storage requirement of 227.7 PJ, 28.0 PJ of market-based storage is required in addition to the 199.7 PJ of utility-owned cost-based storage. The 2024 market-based storage requirement of 28.0 PJ is an increase of 1.9 PJ from Enbridge Gas's 2023 forecast requirement of 26.1 PJ.

7. Issue 51 addresses the implementation of determinations made for the Phase 2 storage issues. Enbridge Gas proposes that any changes to the load balancing and market-based storage costs, as determined in Phase 2 of this Application, be recorded in and recovered through the gas cost deferral accounts until the issues related to cost allocation and rate design are determined in Phase 3 of this Application.

8. Other issues impacting gas supply transportation and storage costs are addressed at the following related areas of evidence:[4]

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[4] Issue 18, part b) was completely settled as part of the Phase 1 Settlement Agreement and therefore is not included in Phase 2 evidence.

a) Issue 18, part c)[5] was partially settled as part of the Settlement Agreement, with exception of the amount of operational contingency space to be determined in Phase 2, which is addressed at Phase 2 Exhibit 4, Tab 2, Schedule 4.
b) Issue 47[6] is addressed at Phase 2 Exhibit 4, Tab 2, Schedule 8, Storage Space Regulation.
c) Issue 48[7] is addressed at Phase 2 Exhibit 4, Tab 2, Schedule 9, Purchase of Market Based Storage.
d) Issue 50[8] is addressed at Phase 2 Exhibit 1, Tab 13, Schedule 2, Unregulated Storage Cost Allocations and Eliminations.

<u>Overview</u>

9. This evidence provides an overview of the approach used to determine the proposed 2024 storage requirement of 227.7 PJ in the Gas Supply Plan. Enbridge Gas balanced overall cost and risk in determining the 2024 storage requirement.

10. To determine the 2024 storage requirement, Enbridge Gas started with the aggregate excess methodology consistent with the methodology used by both EGD and Union, including semi-unbundled[9] contracted storage. Enbridge Gas then examined the impact of operational contingency and utility storage injection and withdrawal capabilities on storage requirements, storage utilization, total cost, and

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[5] Issue 18 c) Is the proposed harmonized approach to determining gas costs (design day, operational contingency space, unaccounted for gas, Parkway Delivery Obligation) appropriate?
[6] Issue 47) Should the cap on cost-based storage service for in-franchise customers established in the NGEIR decision remain at 199.4 PJ?
[7] Issue 48) Is the purchase of storage service at market-based rates by Enbridge Gas from Enbridge Gas for in-franchise customers appropriate?
[8] Issue 50) Is the allocation of capital assets and costs between utility and non-utility (unregulated) storage operations appropriate?
[9] Enbridge Gas's Union South semi-unbundled service was previously referred to as Union South T-Service.

overall risk to ratepayers. Finally, Enbridge Gas engaged ICF to provide an assessment of the approach to meet the Company's load balancing needs for in-franchise customers.

11. Throughout this Exhibit, Enbridge Gas outlines the approach and considerations made in the determination of the 2024 storage requirement and discusses the first-hand experience Enbridge Gas has in operating this level of storage to the benefits of ratepayers.

12. ICF's analysis demonstrates the value of storage that is experienced during extreme weather events. A recent example of the value of Enbridge Gas's storage portfolio was during Winter Storm Uri that occurred in February 2021. This storm caused loss of production due to freeze-offs, pipeline force majeures and staggering financial consequences across the natural gas industry. Significant costs incurred by utilities on behalf of customers were reported across the natural gas industry, such as Atmos Energy ($2 billion USD)[10], CenterPoint Energy ($1.1 billion USD)[11] and Xcel Energy ($1 billion USD)[12]. Enbridge Gas has not experienced similar outcomes during peak winter weather events, largely attributable to the performance of its storage portfolio during these critical periods. This Exhibit outlines how storage is used to protect ratepayers from these types of events and supports the proposal to modestly increase the level of storage required to service in-franchise customers.

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[10] Forbes. (2022 August 24). Texas Consumers On Hook For $10 Billion In Debt Incurred During Winter Storm Uri. https://www.forbes.com/sites/robertbryce/2022/08/24/texas-consumers-on-hook-for-10-billion-in-debt-incurred-during-winter-storm-uri/?sh=2ff67e57f091
[11] Ibid
[12] Utility Dive (2021 April 30). Xcel takes nearly $1B fuel cost hit from February storms but still sees Q1 profit rise. https://www.utilitydive.com/news/xcel-takes-nearly-1b-fuel-cost-hit-from-february-storms-but-still-sees-q1/599330/

13. In accordance with the OEB NGEIR Decision[13] and confirmed in the OEB's MAADs Decision[14], the amount of cost-based storage reserved for customers in the EGD and Union rate zones is 99.4 PJ and 100.0 PJ, respectively. In addition, 0.3 PJ of cost-based storage related to the EGD Crowland storage facility was not included at the time of the OEB NGEIR Decision. In total, Enbridge Gas has 199.7 PJ of cost-based storage available for in-franchise customers.

14. Enbridge Gas proposes to meet the 2024 storage requirement of 227.7 PJ using 199.7 PJ of cost-based storage[15], and 28.0 PJ of market-based storage. The 28.0 PJ of market-based storage represents an increase of 1.9 PJ from Enbridge Gas's 2023 forecast level of 26.1 PJ.

Table 1
Summary of Enbridge Gas's 2024 Storage Requirement

Line No.	Particulars (PJ)	2023 Bridge Year	2024 Test Year	Change
		(a)	(b)	(c)
1	Cost-Based Storage	196.2	199.7	3.5
2	Market-Based Storage	26.1	28.0	1.9
3	Storage Requirement	222.3	227.7	5.4

15. 2024 cost-based storage is 3.5 PJ higher than 2023 as shown in Table 1. 2023 storage requirements for the Union rate zones resulted in excess utility storage space that was sold short-term at market-based rates. Upon approval of the storage proposals in Phase 2, the excess utility storage space of the Union rate zones will be used to serve all Enbridge Gas in-franchise customers.

[13] EB-2005-0551, Decision with Reasons, November 7, 2006.
[14] EB-2017-0306/0307, OEB Decision and Order, August 30, 2018.
[15] Includes 0.3 PJ of storage related to the Crowland storage facility located outside of Tecumseh.

16. Enbridge Gas's 2024 storage requirement includes 28.0 PJ of storage that will continue to be procured by Enbridge Gas in the competitive market. This is consistent with the OEB NGEIR Decision[16] as discussed as part of Issue 47, provided at Phase 2 Exhibit 4, Tab 2, Schedule 8. Issue 48 is addressed at Phase 2 Exhibit 4, Tab 2, Schedule 9, which supports Enbridge Gas's current practice of purchasing storage services for in-franchise customers at market-based rates, including purchases of storage services from Enbridge Gas's non-utility operation, subject to the blind RFP process.

17. Table 2 outlines the 5.4 PJ increase in the 2024 storage requirement compared to the 2023 storage requirement.

Table 2
Summary of Change in Storage Requirement

Line No.	Particulars (PJ)	Storage Requirement
1	2023 Storage Requirement	222.3
	2024 Changes:	
2	In-franchise Aggregate Excess Increase	4.8
3	In-franchise Semi-Unbundled Increase	0.1
4	Operational Contingency Requirement	(9.5)
5	ICF Recommendation for Load Balancing	10.0
6	Total 2024 Changes	5.4
7	2024 Storage Requirement	227.7

[16] EB-2005-0551, Decision with Reasons, November 7, 2006.

18. This evidence includes a review of the load balancing portfolio, as agreed to by Enbridge Gas in the 2021 Gas Supply Plan Annual Update[17] and subsequently in the Settlement Agreement for the 2020 Utility Earnings and Disposition of Deferral and Variance Account Balances proceeding[18]. Enbridge Gas engaged ICF to provide an economic evaluation of the appropriate mix of storage as compared to winter supply purchases and delivered supply alternatives as part of its load balancing portfolio.

19. As part of the Phase 1 Settlement Agreement, parties agreed that there would be no Phase 1 base rate adjustments for gas costs that are subject to deferral, including the load balancing and market-based storage costs.[19] As such, costs currently recovered in rates and gas cost deferral accounts continues to be based on 26.1 PJ of market-based storage. Enbridge Gas proposes that any changes to the load balancing and market-based storage costs, as determined in Phase 2 of this Application, continue to be recorded in and recovered through the gas cost deferral accounts until the issues related to cost allocation and rate design are determined in Phase 3 of this Application[20].

20. Enbridge Gas anticipates that the earliest it can implement storage-related changes to the gas supply portfolio as a result of an OEB decision in Phase 2 would be for the 2025/2026 gas year.

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[17] EB-2021-0004.
[18] EB-2021-0149, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, October 4, 2021, pp.11-12.
[19] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.35.
[20] As part of Phase 3, Enbridge Gas will include the costs associated with the 2024 Gas Supply Plan. Should the amount of market-based storage costs change due to the OEB decision in Phase 2, the final approved costs would be updated in rates as part of the Phase 3 draft rate order. This approach is consistent with the update to 2024 Gas Supply Plan costs, as per the Settlement Agreement.

21. Enbridge Gas is requesting OEB approval for forecast load balancing costs[21] of $17.3 million and market-based storage costs of $25.3 million. Included in the $25.3 million of market-based storage costs is $11.4 million related to implementing ICF's recommendation for 10 PJ of storage for load balancing. The $11.4 million of storage costs for load balancing is partially offset by commodity costs savings of $5.8 million[22]. The 2024 Test Year gas cost forecast has been updated at Attachment 1 for the proposals in this Application.

22. This evidence is organized as follows:
    1. 2024 Storage Requirement
    2. Value of Storage to Enbridge Gas Ratepayers – Load Balancing Portfolio Assessment
    3. Updated Cost of 2024 Storage Requirement
    4. Implementation Plan

1. 2024 Storage Requirement

23. Enbridge Gas is proposing a total 2024 storage requirement of 227.7 PJ for in-franchise customers. Consistent with Enbridge Gas's prior approach to managing EGD contracted market-based storage, Enbridge Gas plans to keep the storage level at 227.7 PJ for the duration of the IR term and propose a new storage level at the next rebasing proceeding. If circumstances change materially and Enbridge Gas requires a change to the level of market-based storage within the IR term, Enbridge Gas will update the OEB and stakeholders accordingly at a future Annual Gas Supply Plan Update.

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[21] Load balancing and market-based storage costs are provided at Attachment 1, p. 4.
[22] Based on the April 2022 QRAM commodity price forecast.

24. To determine the 2024 storage requirement, Enbridge Gas first calculated the amount of in-franchise storage space required using the aggregate excess methodology for bundled customers and contracted storage space by semi-unbundled customers. Second, Enbridge Gas evaluated the impact to the storage requirement related to the amount of firm injection and withdrawal capability available to serve in-franchise customers (as outlined in Phase 2 Exhibit 4, Tab 2, Schedule 5) and the impact related to the harmonized treatment of operational contingency, as discussed below. Finally, the Company hired a third-party consultant, ICF, to review the storage requirement used to serve in-franchise customers.

25. The following subsections provide an overview of each component of Enbridge Gas's proposed 2024 storage requirement.

1.1. Aggregate Excess Methodology

26. Enbridge Gas's storage requirement for bundled in-franchise customers calculated using the aggregate excess methodology is 202.7 PJ.[23] The aggregate excess methodology was used by both EGD and Union for the purposes of determining storage requirements for bundled in-franchise customers. The OEB has accepted the use of the aggregate excess methodology for determining storage requirements[24] and described the methodology as follows:

> The aggregate excess method is the difference between the amount of gas a customer is expected to use in the 151-day winter period and the amount that would be consumed in that period based on the customer's average daily consumption over the entire year.[25]

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[23] Aggregate excess calculation: total winter consumption – [(151/365) x (total annual consumption)]
[24] EB-2005-0551, Decision with Reasons, November 7, 2006, p.85.
[25] EB-2005-0551, Decision with Reasons, May 22, 2007, p.59.

1.2. Semi-Unbundled Storage Requirements

27. Enbridge Gas's storage requirement for semi-unbundled in-franchise customers is 15.0 PJ. The semi-unbundled storage requirement is the amount of storage space contracted by semi-unbundled customers[26]. Union semi-unbundled customers have the following four OEB-approved maximum storage space allocation methodologies available to them:
    a) Aggregate excess;
    b) 15 x obligated daily contract quantity (DCQ);
    c) Peak hourly consumption x 24 x 4 days; or
    d) Contract demand x 10.

28. Semi-unbundled customers contract for and manage their own supply and allocated storage account. The amount of storage contracted by semi-unbundled customers is reflected in the Gas Supply Plan.

1.3. Operational Contingency

29. EGD and Union had different approaches regarding how operational contingency was accounted for in each respective Gas Supply Plan.

30. Union's Gas Supply Plan set aside 9.5 PJ of storage space that was reserved exclusively for operational contingency purposes and was not planned to be used as part of the Gas Supply Plan. This planning method resulted in planned storage requirements above the level identified by the aggregate excess methodology.

31. EGD's Gas Supply Plan considered operational experience and a third-party study to determine planned storage requirements. This planning method resulted in

[26] Union South rate classes Rate T1, Rate T2, and Rate T3.

contracted storage above the level identified by the aggregate excess methodology to manage operational risks and the risk of increased costs to customers. Unlike Union, EGD did not set aside additional storage for operational contingency purposes. Instead, EGD managed operational contingency within its storage portfolio using inventory targets, and therefore, EGD did not plan to use all of its storage portfolio to meet demand requirements.

32. To harmonize the operational contingency approach in its Gas Supply Plan as a starting point for the ICF analysis, Enbridge Gas evaluated two alternatives consistent with the two approaches used by EGD and Union. The first alternative, the "alternative option" included in Table 3, was to include an incremental 15.6 PJ of storage above the amount that was calculated using aggregate excess[27]. This option aligns with the approach used by Union and would result in a total storage requirement of 233.3 PJ as provided in Table 3. This method would allow Enbridge Gas to plan to use the entirety of the storage space calculated by aggregate excess to serve customer demands, however it also results in a higher total storage requirement than the second alternative, as described below.

[27] Enbridge Gas's 15.6 PJ of operational contingency required is outlined in Phase 2 Exhibit 4, Tab 2, Schedule 4.

33. The second alternative, the "preferred option" included in Table 3, was to apply inventory targets embedded within the storage space calculated by aggregate excess to manage the 15.6 PJ of operational contingency requirements. This option aligns with the approach used by EGD. This method reserves 15.6 PJ within the storage space calculated by aggregate excess such that, on a planned basis, it will not be used to serve customer demands during the winter. This space will only be used on an actual basis for purposes described in Phase 2 Exhibit 4, Tab 2, Schedule 4.

Table 3
Operational Contingency Alternatives – 2024 In-franchise Storage Requirement

Line No.	Particulars (PJ)	Alternative Option (a)	Preferred Option (b)
1	Aggregate Excess	202.7	202.7
2	Semi-Unbundled Storage	15.0	15.0
3	Operational Contingency	15.6	N/A (1)
4	Total Storage	233.3	217.7

Note:
(1) 15.6 PJ of space required for operational contingency is embedded in line 1 and reduces the storage available to meet demand requirements by this amount.

34. Enbridge Gas chose the "preferred option" as a starting point for the ICF analysis, which would serve as an input into Enbridge Gas's evaluation of the overall balance between total portfolio cost and risk. Further details of Enbridge Gas's operational contingency requirements are outlined in Phase 2 Exhibit 4, Tab 2, Schedule 4.

1.4. Utility Storage Injection and Withdrawal Capability – Impact on Gas Supply Plan

35. Enbridge Gas's 2024 Gas Supply Plan includes firm injection and withdrawal capacity available from both cost-based storage and market-based storage to serve

in-franchise customers. The amount of firm injection and withdrawal capacity available from cost-based storage is outlined in Phase 2 Exhibit 4, Tab 2, Schedule 5. The maximum firm withdrawal capability is 3.8 PJ/d and the maximum firm injection capability is 1.7 PJ/d associated with total cost-based storage space of 199.4 PJ established with the OEB NGEIR Decision[28]. The impact of the firm cost-based withdrawal capabilities is a 0.3 PJ/d decrease in storage withdrawals on the design day compared to 2023. Accordingly, Enbridge Gas's Gas Supply Plan reflects an increase in Dawn purchases. As part of the execution of the Gas Supply Plan, Enbridge Gas will continue to monitor inventory positions and will procure supply when required to meet actual demand requirements throughout the year.

1.5. ICF Analysis and Recommendation.

36. As outlined above, Enbridge Gas's proposed approach to operational contingency and firm utility injection and withdrawal capacity in the Gas Supply Plan results in a lower 2024 storage requirement compared to approaches which would require increasing the 2024 storage requirement to manage these items. The proposed approach results in a lower cost to ratepayers on a forecast basis due to a lower storage requirement, however, the approach results in an increase in the level of risk of the Gas Supply Plan as a result of increases in the amount of winter purchases at Dawn. Enbridge Gas made the decision on the approach with the knowledge that ICF would be performing its analysis on the total storage portfolio. Enbridge Gas planned to use the outcome of ICF's analysis to evaluate the overall balance between cost and risk as part its 2024 load balancing portfolio.

37. ICF recommended that Enbridge Gas contract for 10 PJ of storage for load balancing, representing an appropriate balance between cost and risk, as outlined

[28] EB-2005-0551, Decisions with Reasons, November 7, 2006.

in their report provided at Attachment 3. As outlined below in Section 2, ICF evaluated economic impacts to Enbridge Gas's portfolio under different levels of storage capacity. The starting point of ICF's analysis reflected Enbridge Gas's preferred option of embedding operational contingency requirements in the aggregate excess storage, rather than procuring incremental storage for operational contingency. Contracting for 10 PJ for load balancing in the storage requirement partially offsets the increased volume of gas supply required to be purchased at Dawn on a design day. Absent this storage, reliance on design day purchases would be higher primarily due to the maximum firm storage injection and withdrawal capability parameters, and the proposed treatment of operational contingency. Enbridge Gas's proposal reflects a balance between cost and risk, and results in a lower storage requirement than the "alternative option" provided in Table 3. As discussed in Section 2, Enbridge Gas's total 2024 storage requirement is supported by historical experience and actual benefit from operating this level of storage.

38. The recommended 10 PJ of storage for load balancing provides approximately 120 TJ/d of firm withdrawal rights during the winter. As discussed in Section 2, Enbridge Gas already purchases a significant amount of its winter supply in the winter months.

39. The alternative to contracting for the recommended 10 PJ of storage is to add 120 TJ/d to the winter purchases that Enbridge Gas already plans at Dawn. In this scenario, operational flexibility is reduced and overall risk increases. Enbridge Gas would need to decide whether to secure this supply months or weeks in advance, or to wait to confirm near-term customer demands and purchase the supply in the day ahead or cash market. Purchasing an additional 120 TJ/d in the day ahead or

cash market exposes ratepayers to significant price volatility risk, as natural gas prices can increase significantly in the short-term market during peak demand periods. Additionally, there is significant operational risk associated with too much reliance on next-day or same-day deliveries of gas, as supply may not be available on such short notice and/or Enbridge Gas may have difficulty contacting suppliers in instances where requirements arise on weekends or holidays, as was the case with Winter Storm Elliott during the holiday weekend in December 2022.

40. As discussed throughout this Exhibit, Enbridge Gas is confident that the proposed in-franchise storage requirement of 227.7 PJ reflects the appropriate balance of cost and risk and results in a Gas Supply Plan that is reliable, operationally flexible, and cost effective.

1.6. Summary

41. Enbridge Gas is proposing to meet the 2024 storage requirement of 227.7 PJ as provided in Table 4. The 2024 storage requirement will be met through cost-based storage of 199.7 PJ and market-based storage of 28.0 PJ.

Table 4
In-franchise Storage Space Requirement

Line No.	Particulars (PJ)	2023 Bridge Year	2024 Test Year
		(a)	(b)
	In-franchise Storage Space Requirement		
1	In-franchise Aggregate Excess	197.9	202.7
2	In-franchise Semi-Unbundled Storage	14.9	15.0
3	Operational Contingency Requirement	9.5	0.0 (1)
4	ICF Recommendation for Load Balancing	-	10.0
5	Total Storage Requirement	222.3	227.7
	Storage Space Allocated for In-franchise Use		
6	Dawn	96.5 (2)	100.0
7	Tecumseh	99.4	99.4
8	Crowland	0.3	0.3
9	Total Cost-Based Storage	196.2	199.7
10	Market-Based Storage	26.1	28.0
11	Total Storage Space	222.3	227.7

Notes:
(1) 15.6 PJ of operational contingency space is embedded in line 1 and reduced the amount of storage available to meet demand requirements.
(2) Excludes Union's excess utility space that historically existed in the Union rate zones and was sold short-term at market-based rates. Beginning in 2024, the excess utility storage space will be used to serve all Enbridge Gas in-franchise customers.

2. Value of Storage to Enbridge Gas Ratepayers – Load Balancing Portfolio Assessment

42. Enbridge Gas agreed as part of the 2021 Annual Gas Supply Update[29] to provide more information on its use of storage within its load balancing portfolio as part of the 2024 Rebasing proceeding, and subsequently in the Settlement Agreement for

[29] EB-2021-0004.

the 2020 Utility Earnings and Disposition of Deferral and Variance Account Balances Application[30]:

> In connection with the settlement of this item, Enbridge has agreed to file evidence in its rebasing application (for rates as of January 1, 2024, which will include requests for approvals for the pass-through of gas supply costs) demonstrating that it has fully considered the opportunity to reduce storage costs through inclusion, as part of its load balancing portfolio, of cost-effective market-based alternatives to the purchase of third-party storage. That evidence will include consideration of: (i) the cost of delivered supply (including the commodity cost) in winter in lieu of contracting for additional storage: versus (ii) the cost (savings) of buying gas in summer and the associated additional storage and related costs required to store and redeliver that gas in the winter.

43. In response, Enbridge Gas engaged ICF to provide an economic evaluation of the appropriate mix of storage as compared to delivered supply in the winter as part of its load balancing portfolio over a 5-year term. The ICF Reports are provided at Attachments 2 and 3.

2.1. Load Balancing Background

44. Load balancing is the practice of managing supply that is above or below average day demand throughout the year. Enbridge Gas plans load balancing requirements for system and bundled Direct Purchase (DP) customers through a combination of withdrawals from and injections into storage, purchases of gas supply at Dawn, and third-party services. On an actual basis, load balancing requirements may be higher or lower than planned due to customer demand being above or below forecast

[30] EB-2021-0149, Settlement Agreement, October 4, 2021, pp.11-12.

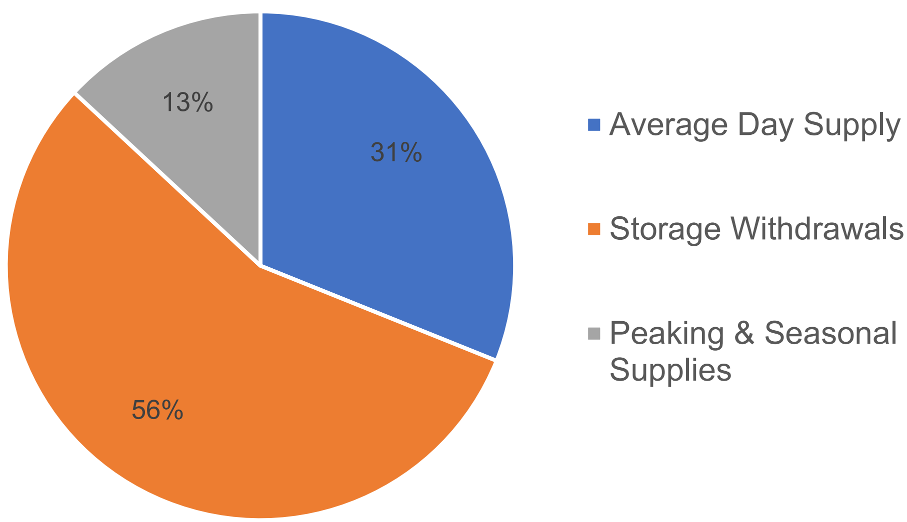
demand. Enbridge Gas manages these unplanned load balancing requirements for system customers only. Unplanned load balancing requirements may be met through storage injections or withdrawals, adjustments of planned supply purchases, and third-party services. Enbridge Gas has proposed that all bundled DP customers will be responsible for their own unplanned load balancing requirements through their obligation to meet their checkpoints at the end of February and September each year, consistent with the bundled DP customer load balancing requirements in the Union South rate zone. The harmonization of DP services will be addressed as part of Phase 3 of this Application. More information on bundled DP customer load balancing requirements is provided at EB-2022-0200 Exhibit 8, Tab 4, Schedule 3.

45. On a planned basis, Enbridge Gas supply purchases are weighted within the year to winter purchases when demands are higher, meaning that more Dawn supply is planned to be purchased in the winter months than the summer months. Enbridge Gas plans to use purchases at Dawn to meet planned load balancing requirements in the winter months. In addition, a significant portion of unplanned load balancing requirements will also be managed using purchases at Dawn. Enbridge Gas uses a combination of supply purchased and transported using upstream pipelines, winter supply purchases at Dawn, peaking services, and the deliverability available from storage to manage unplanned load balancing requirements. This diversified portfolio results in a reliable and cost-effective suite of assets to support customer load balancing requirements.

46. As shown in Figure 1, approximately half of Enbridge Gas's design day demands are met with storage services, with the other half met by purchased or obligated supply to be delivered in the winter months. It is important to note that available

upstream natural gas transportation capacity into Ontario is not sufficient to meet the design day supply requirements of Enbridge Gas's customers without the use of storage withdrawals at Dawn. Therefore, storage services represent a significant and necessary portion of Enbridge Gas's load balancing portfolio.

Figure 1: Summary of Design Day Supply



2.2. Value of Storage

47. The benefits to ratepayers of Enbridge Gas's storage portfolio were clearly demonstrated by a recent extreme weather event, Winter Storm Elliott, which occurred between December 22 and December 26, 2022. The deep freeze that occurred during this period had an impact on the pipelines that move natural gas around North America, including those that bring supply to Dawn. Appalachian gas producers experienced widespread production freeze-offs which resulted in significant force majeures called on downstream supply transactions. Enbridge Gas received notices of force majeure impacting over 230 TJ of supply deliveries contracted to flow to Dawn. Enbridge Gas was able to maintain service to its

customers amid the lost supply using significant withdrawals from its utility-owned storage and contracted storage services.

48. In addition to the economic benefits of holding storage, ICF highlights at page 46 of Attachment 3 other benefits to the Gas Supply Plan that were clearly demonstrated during Winter Storm Elliott:

> In addition, the incremental storage capacity would increase system reliability and resiliency and is expected to lead to additional cost savings due to the flexibility in gas purchase timing facilitated by the incremental storage capacity.

49. The inclusion of storage assets in the Gas Supply Plan provides a cost-effective, reliable, and secure alternative to purchasing commodity when required by customers, which is consistent with the OEB's guiding principles.

50. Enbridge Gas has included both cost-based and market-based storage in its in-franchise storage portfolio. Cost-based storage is utility-owned storage that is included within rate base. Market-based storage is contracted in the competitive marketplace at a negotiated market price for terms of one to five years, which provides flexibility to the Gas Supply Plan should there be a future reduction to in-franchise storage service requirements. There are two components of market-based storage prices: intrinsic value and extrinsic value.

51. Intrinsic storage value is the value derived from being able to procure gas during the summer, when prices are typically lower, and withdraw that gas in the winter, when prices are typically higher. Intrinsic value is dependent on both the firm injection and withdrawal parameters of the storage service and forward natural gas

market prices at any given time. As a simplified example, storage services that allow for firm injections throughout the summer and firm withdrawals throughout the winter would have intrinsic value that is roughly guided by the summer-winter forward market spread (difference between forecast summer commodity price and forecast winter commodity price).

52. Extrinsic storage value is largely specific to each purchasing party and driven by multiple factors beyond forward market spreads. The factors used to evaluate the extrinsic value of storage services include, but are not limited to:
    a) The availability of storage services being requested by buyers;
    b) The market demand for storage;
    c) The proximity of the storage service to the demand location;
    d) The reliability of the storage service;
    e) The flexibility of the storage service to vary injections and withdrawals throughout the year;
    f) The inclusion of interruptible injection and withdrawals and the reliability of these interruptible services; and
    g) The market volatility in and around the injection and withdrawal location such that intrinsic valuation provides an incomplete representation of prices that may be experienced through the actual injection and withdrawal periods.

53. Due to these complexities, extrinsic storage value is very difficult to quantify in advance and is often estimated as the difference between the contracted storage price and the intrinsic storage value.

2.3. *ICF Analysis – October 2022*

54. The starting point for the ICF analysis is based on Enbridge Gas's 2024 demand forecast, reflecting load balancing requirements calculated using aggregate excess and a weather normal demand forecast, resulting in 202.7 PJ of storage required for 2024[31]. To evaluate the economic impact of changes to Enbridge Gas's storage portfolio compared to winter commodity purchases, ICF compared total portfolio costs under different levels of storage capacity and delivered services. The different levels of storage capacity and delivered services evaluated were based on various weather-related commodity pricing scenarios (weather scenarios).[32]

55. At page 8 of Attachment 3, ICF noted in their analysis that the consideration of actual weather and resulting commodity prices is an important consideration on storage values, providing a more complete assessment of the range of impacts that storage provides.

56. Using the commodity price forecasts from the weather scenarios provided by ICF, Enbridge Gas evaluated varying levels of storage capacity between 203.0 PJ to 233.0 PJ[33] to determine total portfolio cost under each weather scenario over a 5-year term. ICF used this information to assess the relative value of different amounts of storage capacity.

[31] ICF's analysis of total storage requirement is prior to the 15.0 PJ requirement for semi-unbundled customers.
[32] The four weather scenarios evaluated by ICF and outlined on page 7 of their report include: (1) normal weather (consistent with Enbridge Gas normal weather assumptions), (2) warmer than normal weather, (3) typical weather, and (4) colder than normal weather.
[33] Enbridge Gas evaluated three 10 PJ tranches of incremental market-based storage in addition to the 2024 aggregate excess storage requirement of 203 PJ.

57. ICF calculated cost impacts of fixed levels of storage capacity and evaluated four different scenarios that included fixed storage capacities[34] of 208.0 PJ, 211.0 PJ, 213.0 PJ, and 223.0 PJ over the 5-year term, using the typical weather scenario.[35] ICF concluded on pages 12 and 13 of Attachment 3, that total portfolio costs were relatively flat across the range of four scenarios of incremental storage capacity evaluated, increasing between 0.008% and 0.2% depending on the amount of storage capacity added. This relatively minor cost increase provides a means to mitigate delivered natural gas price volatility as it would mitigate exposure to extreme weather events and high natural gas prices such as those experienced during the polar vortex winter of 2013/2014 and Winter Storm Uri in February 2021.

58. ICF also evaluated the economic impacts of Enbridge Gas holding 198.0 PJ of total storage, which is approximately 5.0 PJ less than the 2024 aggregate excess less the operational contingency requirement. The purpose of evaluating the 5.0 PJ decrement was to evaluate the cost-effectiveness of a scenario whereby Enbridge Gas held an amount of storage in its portfolio below aggregate excess with operational contingency storage targets embedded. ICF concluded at Exhibit 3-1 on page 29 of Attachment 3, that this scenario resulted in average annual portfolio cost increases between $0.2 million to $11 million, depending on the weather scenario evaluated. As a result, ICF concluded at page 13 that the amount of storage calculated by the aggregate excess methodology was appropriate for purposes of determining minimum storage requirements, from a cost effectiveness perspective.

[34] As noted above, 15.6 PJ out of the total storage capacity being evaluated in each scenario was reserved for operational contingency purposes, resulting in a starting point below aggregate excess for purposes of evaluating storage requirements. This is consistent with all scenarios evaluated by ICF.

[35] The typical weather scenario is based on five years of actual weather that was closest to the normal weather scenario. Based on this, actual weather during the 2008-2012 period had HDDs that were closest to the normal weather scenario.

59. As part of the analysis, ICF evaluated market-based alternatives to storage and whether these alternatives could reduce the need for storage capacity. Alternatives to storage capacity that were evaluated include (1) additional pipeline capacity to serve the load served by storage, and (2) incremental winter Dawn purchases combined with winter peaking service that could offset the storage contributions to design day. ICF ultimately concluded at page 27 of Attachment 3 that these alternatives would not be preferrable to obtaining market-based storage:

> ICF concluded that there could be viable market-based alternatives to market-based storage capacity, but these alternatives would not be preferable to market-based storage capacity due to a combination of factors including economics, system reliability benefits including contributions to design day capacity planning, and reductions in supply cost volatility to consumers.

2.4. ICF Recommendation

60. ICF recommends that in addition to the 202.7 PJ storage requirements calculated using the aggregate excess methodology, Enbridge Gas should consider adding market-based storage of 10 PJ:

> ICF recommends the 10 PJ of incremental storage capacity as the best balance between the projected value of the incremental storage capacity to minimize gas supply costs, the value of reducing gas cost uncertainty and volatility, and the reliability benefits provided by storage capacity, and the fixed cost commitments needed to contract for the storage capacity.[36]

[36] Attachment 3, p. 46.

61. The outcome of ICF's analysis is that Enbridge Gas should consider increasing the amount of market-based storage that Enbridge Gas holds compared to the 2023 forecast requirement by 1.9 PJ for a total of 28.0 PJ.

2.5. Addendum to the ICF Report – February 2024

62. Enbridge Gas engaged ICF in 2024 to update the 2022 ICF Report for the purpose of assessing the impact of market changes and changes in storage pricing that have occurred since the original analysis was completed in 2022. The 2024 ICF Addendum Report can be found at Attachment 2.

63. The most significant updates in the 2024 ICF Addendum Report reflect the baseline cost of market-based storage reflected in the analysis, and the changes to market conditions that impact the long-term price outlook for natural gas. The 2022 ICF Report used a market-based storage cost of $0.87/GJ, and the 2024 ICF Addendum Report reflected a market-based storage cost of $1.28/GJ, both of which were based on actual costs incurred for storage during these periods. As explained by ICF in the 2024 ICF Addendum Report[37], the long-term price outlook for natural gas has increased due to a range of factors, including LNG exports, inflationary pressures, impacts from higher-than-expected prices in 2022 and decreases in prices experienced in 2023. As a result, the seasonal difference in natural gas prices are expected to increase and lead to higher intrinsic value for use of natural gas.

64. As noted above, the 2022 ICF Report concluded that total portfolio costs were relatively flat across the range of four scenarios of incremental storage capacity

[37] Attachment 2, pp.3-4.

evaluated, increasing between 0.008% and 0.2% depending on the amount of storage capacity added.

65. The 2024 ICF Addendum Report concludes that total portfolio costs for the typical weather scenario decreased between $24 million to $49 million (compared to the base case/normal weather scenario), or a decrease between 0.161% to 0.325% of total portfolio costs, depending on the amount of incremental market-based storage added to the portfolio[38].

66. The 2024 ICF Addendum Report also updated the evaluation of the impact on total portfolio costs of reducing market-based storage capacity by 5 PJ. As noted above, the 2022 ICF Report concluded average annual portfolio costs increased between $0.2 million to $11 million, depending on the weather scenario evaluated. As outlined starting on page 30, the 2024 ICF Addendum Report results in a more pronounced cost increase related to reducing the amount of market-based storage by 5 PJ, with average annual portfolio costs increasing between $3 million to $16 million, depending on the weather scenario evaluated.

67. The 2024 ICF Addendum Report confirms the 2022 ICF Report recommendation of adding 10 PJ of market-based storage in addition to the amount calculated using the aggregate excess methodology. ICF's updated analysis concludes that since the previous analysis was completed, the value of natural gas storage to Enbridge Gas customers has increased faster than the cost of incremental market-based storage capacity, as demonstrated by the total portfolio cost reductions calculated under the typical weather scenario. Accordingly, Enbridge Gas's proposal to add 10

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[38] Attachment 2, pp.28-29.

PJ of market-based storage remains unchanged and is consistent with ICF's recommendation in the 20204 ICF Addendum Report.

3. Updated Cost of 2024 Storage Requirement

68. Enbridge Gas has updated the Gas Supply Plan for the 2024 Test Year Forecast at Attachment 1 to include cost associated with the 10 PJ of market-based storage for load balancing from ICF's recommendation. The cost associated with the 10 PJ of market-based storage was not included in the gas supply plan costs at EB-2022-0200 Exhibit 4, Tab 2, Schedule 1, paragraph 5, due to the timing of the ICF engagement relative to the Phase 1 filing date. Attachment 1 reflects the cost of all proposals discussed in this Exhibit.

4. Implementation Plan

69. As noted in this Exhibit, the timing between receiving an OEB decision on this Application and Enbridge Gas's implementation of storage related changes to its gas supply portfolio would result in gas cost deferral and variance account balances. Enbridge Gas estimates that contracting changes for storage services could be implemented as early as April 1, 2025. As outlined above, costs associated with the 2023 forecast amount of market-based storage included in the gas supply portfolio of 26.1 PJ continue to be recovered in rates and gas cost deferral accounts. Enbridge Gas proposes that any changes to the load balancing and market-based storage costs, as determined in Phase 2 of this Application, continue to be recorded in and recovered through the gas cost deferral accounts

until the issues related to cost allocation and rate design are determined in Phase 3 of this Application.[39]

[39] As part of Phase 3, Enbridge Gas will include the costs associated with the 2024 Gas Supply Plan. Should the amount of market-based storage costs change due to the OEB determination in Phase 2, the final approved costs would be updated in rates as part Phase 3. This approach is consistent with the update to 2024 Gas Supply Plan costs, as per the Settlement Agreement.

Summary of Gas Costs

Line No.	Particulars ($ millions)	Utility	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Supply									
1	Western Canadian Sedimentary Basin	EGI	207.3	198.4	254.4	276.4	455.0	712.3	414.7	549.7
2	Ontario / Dawn	EGI	540.4	932.7	713.8	357.8	585.9	1,187.0	452.0	675.1
3	Appalachia	EGI	0.0	81.9	288.8	192.5	364.1	688.4	276.9	487.9
4	Niagara	EGI	278.3	292.2	248.1	194.5	344.9	613.2	223.5	398.2
5	Chicago	EGI	477.1	353.3	172.2	120.4	243.3	488.8	190.0	391.1
6	U.S. Mid-Continent	EGI	49.1	42.0	36.5	37.7	95.0	156.3	57.2	117.5
7	Michigan	EGI	143.0	96.2	0.0	0.0	0.0	0.0	0.0	0.0
8	Gulf Coast	EGI	24.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Third-party Services	EGI	1.0	5.0	8.4	0.2	0.2	0.0	0.0	0.0
10	Unsecured	EGI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.8
11	Total Supply Costs - EGI		1,720.9	2,001.7	1,722.2	1,179.5	2,088.2	3,846.1	1,614.3	2,664.3
	Transportation									
12	TCPL Long Haul	EGI	204.9	206.0	188.1	184.1	161.5	166.4	163.8	172.7
13	TCPL Short Haul	EGI	211.6	206.9	158.2	149.8	186.9	190.8	189.4	187.6
14	Nexus	EGI	0.0	20.4	119.5	118.5	116.2	120.6	118.9	105.0
15	Vector	EGI	38.2	28.5	21.7	21.7	21.3	25.6	24.2	23.7
16	U.S. Mid-Continent (1)	EGI	10.6	9.7	10.5	20.5	22.1	23.1	(0.3)	19.4
17	Nova	EGI	9.3	10.1	12.1	8.1	8.4	8.3	8.8	8.2
18	Great Lakes	EGI	0.0	0.0	1.4	8.0	8.0	8.7	7.0	6.5
19	Centra Pipelines	EGI	1.3	1.3	1.3	1.3	1.3	1.4	1.5	1.4
20	Michigan	EGI	3.2	3.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Gulf Coast	EGI	2.1	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
22	Other Transportation	EGI	3.2	3.4	3.2	2.4	3.8	3.6	4.3	3.9
23	Total Transportation Costs - EGI		484.4	489.4	515.9	514.4	529.5	548.6	517.7	528.4

Summary of Gas Costs (Continued)

Line No.	Particulars ($ millions)	Utility	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Other Gas Costs & Adjustments									
24	Gas Deferral Adjustment	EGI	23.4	(296.5)	24.8	26.2	(465.9)	(618.6)	486.1	0.0
25	Storage (Injection) / Withdrawal	EGI	117.4	32.3	35.3	89.4	4.8	(128.1)	215.2	6.7
26	Market-Based Storage (2)	EGI	18.3	19.4	20.1	21.5	21.0	21.1	23.5	25.3
27	Parkway Delivery Commitment Incentive	EGI	15.9	13.0	13.1	13.3	14.1	15.4	19.4	17.6
28	Dawn to Parkway Transportation	EGI	80.0	100.5	94.1	89.7	86.6	96.0	99.5	0.0
29	Transportation Optimization	EGI	2.1	2.8	2.3	1.0	1.7	1.1	0.6	0.0
30	Other Adjustments	EGI	(10.1)	71.8	6.8	13.2	(0.1)	23.3	(11.3)	0.0
31	Cap and Trade / Federal Carbon	EGI	586.0	371.5	1.3	3.7	5.0	7.2	8.5	0.0
32	Less: Unregulated Costs	EGI	(0.6)	(1.4)	(3.6)	(0.9)	(3.3)	(3.3)	(5.8)	(8.6)
33	Less: Affiliate Adjustment	EGI	(15.6)	(16.8)	(167.0)	(169.9)	(171.2)	(178.6)	(180.3)	0.0
34	Total Gas Costs & Adjustments - EGI		816.9	296.5	27.2	87.3	(507.2)	(764.4)	655.5	41.0
35	Total Utility Cost of Gas	EGI	3,022.1	2,787.7	2,265.3	1,781.3	2,110.6	3,630.3	2,787.4	3,233.7

Notes:

(1) 2023 includes a reduction of gas cost for approximately $20 million, related to a refund received from Panhandle pertaining to FERC proceedings regarding over-recovery of costs. Refer to Jan 2024 QRAM proceeding, EB-2023-0330, Exhibit D, Tab 1, Schedule 1.

(2) 2024 includes costs associated with incremental 10 PJ related to the ICF recommendation as discussed in Section 2.

2024 Gas Costs to Operations

Line No.	Particulars	Supply (TJ) (a)	Supply (10^3m^3) (b)	Gas Costs ($000s) (c)
	Supply			
1	Western Canadian Sedimentary Basin	119,828	3,066,217	525,449
2	Ontario / Dawn	125,697	3,216,396	662,115
3	Appalachia	100,399	2,569,061	487,894
4	Chicago	71,438	1,827,986	391,116
5	Niagara	80,923	2,070,700	398,241
6	U.S. Mid-Continent	22,011	563,217	117,460
7	Unsecured	7,056	180,546	38,583
8	Total Supply Costs (1)	527,350	13,494,124	2,620,859
	Transportation Costs - System Gas			
9	TCPL Niagara			15,218
10	Nexus			105,008
11	Vector			23,678
12	U.S. Mid-Continent			19,421
13	Nova			8,222
14	Great Lakes			6,528
15	Total Transportation Costs - System Gas			178,075
16	Total Supply and Transportation Costs - System Gas	527,350	13,494,124	2,798,934

Note:
(1) 2024 Total Supply Costs per page 1, column (h), line 11, excluding upstream transportation fuel costs and load balancing and peaking costs per column (c), lines 8 and 10 in page 4, respectively, ($2,664.3 million - $26.2 million - $17.2 million = $2,620.9 million).

2024 Gas Costs to Operations

Line No.	Particulars	Supply (TJ)	Supply (10^3m^3)	Gas Costs ($000s)
		(a)	(b)	(c)
1	Total Supply and Transportation Costs - System Gas	527,350	13,494,124	2,798,934
2	Storage (Injection) / Withdrawal - System Gas	738	32,519	6,745
3	Total Gas Costs - System Gas	528,089	13,526,643	2,805,679
	Transportation Costs and Transportation Fuel Costs - Third Party			
4	TCPL Long Haul			172,661
5	TCPL Short Haul			172,350
6	Centra Pipelines			1,407
7	Other Transportation			3,867
8	Upstream Transporation Fuel Costs			26,199
9	Total Transportation Costs and Transportation Fuel Costs - Third Party			376,484
	Other Gas Costs			
10	Load Balancing & Peaking (1)			17,253
11	Market Based Storage Costs (2)			25,285
12	Parkway Delivery Commitment Incentive (PDCI)			17,612
13	Total Other Gas Costs			60,149
14	Total Forecasted Gas Costs			3,242,313
	Less: Unregulated Adjustment			
15	Company Use			224
16	Unaccounted For Gas (UFG)			5,863
17	Compressor Fuel			2,545
18	Total Unregulated Adjustment			8,631
19	Total Utility Forecasted Gas Costs			3,233,681

Notes:
(1) Page 5, line 8.
(2) Amount includes costs associated with incremental 10 PJ related to the ICF recommendation.

2024 Load Balancing Calculations

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Days in Month	31	29	30	31	31	30	31	31	30	31	30	31	365
2	Supplies (TJ)	10,439	23,600	0	2,012	4,000	13,200	13,640	2,863	10,923	10,440	10,024	24,150	125,291
3	Average Day Demand Per Month (TJ)	10,612	9,927	10,270	10,612	10,612	10,270	10,612	10,612	10,270	10,612	10,270	10,612	125,291
4	Average Purchases Variance (TJ)	(174)	13,673	(10,270)	(8,600)	(6,612)	2,930	3,028	(7,749)	654	(172)	(246)	13,538	0
5	Dawn Forecasted Price ($/GJ)	5.742	5.662	5.234	5.211	5.136	5.098	5.085	5.091	5.047	5.050	5.294	5.551	
6	Price Variance - Load Balancing ($000s) (1)	(997)	77,408	(53,751)	(44,813)	(33,963)	14,938	15,397	(39,446)	3,298	(869)	(1,301)	75,150	11,051
7	Demand Cost - Load Balancing ($000s)	524	524	524	513	513	513	513	513	513	513	513	524	6,201
8	Total Load Balancing Costs ($000s) (2)	(473)	77,931	(53,227)	(44,300)	(33,449)	15,451	15,911	(38,933)	3,812	(356)	(788)	75,673	17,253

Notes:
(1) Line 4 x line 5.
(2) Line 6 + line 7.

2024 Comparison of Annual System Gas Supply and Demand

Line No.	Particulars	Supply / Demand (TJ)	Supply / Demand (10^3m^3)
		(a)	(b)
	Supplies To Operations		
1	Supplies (1)	527,350	13,494,124
2	Storage (Injection) / Withdrawal - System Gas (2)	738	32,519
3	Total Supplies	528,089	13,526,643
	Demand Forecast		
4	System Gas (3)	513,276	13,147,613
5	Company Use & Other	774	19,798
6	Unaccounted For Gas (UFG)	11,825	302,578
7	Compressor Fuel	7,510	192,172
8	Customer Supplied Fuel	(5,296)	(135,518)
9	Total System Requirements	528,089	13,526,642

Notes:
(1) Page 4, column (a), line 1.
(2) Page 4, column (a), line 2.
(3) EB-2022-0200 Exhibit 3, Tab 3, Schedule 1, Attachment 8, page 14, column (d), line 36.

ADDENDUM TO THE ICF REPORT:

ASSESSMENT OF STORAGE CAPACITY REQUIREMENTS FOR ENBRIDGE GAS INFRANCHISE CUSTOMERS

Addendum to the October 12, 2022 Report

April 16, 2024

Submitted to:
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Contents

1 Introduction and Summary of Conclusions

1.1 Introduction

As part of the Enbridge Gas Inc. (Enbridge Gas) 2024 Rebasing Application (the Application), designed to set rates as of January 1, 2024, Enbridge Gas is proposing to integrate the storage planning process as a result of the amalgamation of Enbridge Gas Distribution (EGD) and Union Gas Limited (Union) on January 1, 2019. Enbridge Gas also agreed to provide more information on storage costs and market-based alternatives to the purchase of third-party storage in its supply portfolio as part of this application.[1]

Enbridge Gas retained ICF to assess the appropriate mix of winter supply purchases as compared to holding storage assets for meeting Enbridge Gas's load balancing needs for bundled service customers. In response to this request, ICF prepared the report titled "Assessment of Storage Capacity Requirements for Enbridge Gas In-franchise Bundled Service Customers", dated October 12, 2022 (the October 2022 Report). The October 2022 Report documented ICF's recommendations on the level of contracted storage capacity that would be optimal for Enbridge Gas and provided an assessment of the determination of Enbridge Gas's natural gas storage requirements relative to other market-based alternatives for bundled service customers. This addendum provides an update to the October 2022 Report.

Since the previous analysis was prepared, Enbridge Gas has seen a significant increase in the cost of market-based storage capacity that would be needed to reach the storage levels recommended by ICF. For the October 2022 Report, ICF used a baseline cost of market- based storage capacity of $0.87 per GJ. This value was based on the most recently available bids offered to Enbridge Gas based on the results of their most recent storage RFP. In the last year, the cost of storage capacity offered to Enbridge Gas increased to $1.28 per GJ. The updated cost of storage capacity served as a starting point for the evaluation of incremental storage capacity in the updated analysis.

In addition, the total supply costs are higher across all scenarios due to the increase in gas supply costs in the updated analysis.

However, the factors that tend to drive up the costs of storage and drive up the overall supply costs also tend to increase the value of storage to Enbridge Gas's distribution customers. Gas markets have significantly shifted since the October 2022 Report analysis was completed. A range of factors, including the Russia-Ukraine war in the first part of 2022, winter Storm Elliot in the last quarter of 2022, and the market readjustment coming out of the Pandemic have resulted in changes in the near to mid-term natural gas price forecasts, and have impacted both storage value and storage cost over the time frame of the storage value analysis.

After witnessing higher than expected natural gas prices in 2022, natural gas prices fell faster than expected in 2023 and have stayed below the $3 per MMBtu mark for most of the 2023/24 winter. However, the long-term price outlook has also increased due to a range of factors including increased LNG exports and inflationary pressures. As a result, gas prices are projected to increase faster between the summer injection season and the winter withdrawal season in the

[1] EB-2021-0004; EB-2021-0149, Settlement Proposal, October 4, 2021, pp.11-12

future, leading to higher seasonal differences in natural gas prices and higher intrinsic values for the use of natural gas storage.

ICF updated the analysis conducted for the October 2022 Report to assess the impacts of the changes in gas markets and storage pricing that have taken place since the original analysis was conducted. The analysis in the October 2022 report was based on ICF's Q2 2022 base case while the analysis in this February 2024 Addendum is based on ICF's Q4 2023 base case. The analysis was also updated to reflect a change in the time frame under consideration. The October 2022 Report considered the 5-year period from April 2023 through March 2028. The updated analysis considers the 5-year period from April 2024 through March 2029.

1.2 Summary of Conclusions

Based on the analysis conducted for the October 2022 Report, ICF made the following recommendation regarding the amount of storage capacity that should be held by Enbridge Gas to support its regulated customers.

> "ICF's analysis suggests that Enbridge Gas should consider increasing the amount of market-based storage capacity held for bundled service customers by about 10 PJ from 18 PJ to 28 PJ. This recommendation reflects a balance between cost, cost volatility, design day reliability, and minimizing up front contract cost commitments for supply services and reflects the results of the assessment of the value of storage under different weather conditions, and the assessment of the impacts of different levels of storage capacity on costs for the typical weather scenario."[2]

The updated analysis validates this recommendation. Overall, the net gas supply costs for bundled in-franchise customers are expected to decline with the addition of incremental storage capacity across a range of storage capacity options when compared to the existing supply portfolio without incremental storage. ICF's analysis indicates that since the previous analysis was completed, the value of natural gas storage to Enbridge Gas bundled service customers has increased slightly faster than the expected cost. The increase in the commodity cost savings achieved by holding additional storage capacity outweighs the increase in demand changes incurred from holding incremental storage capacity. Hence the value of holding incremental storage capacity has increased since the October 2022 Report was prepared.

Based on the updated analysis of the potential value of storage under different weather conditions, and the value of incremental storage capacity, ICF reaffirms the recommendation made in the October 2022 Report that Enbridge Gas consider increasing the amount of market-based storage capacity held for bundled service customers by about 10 PJ from 18 PJ to 28 PJ. ICF continues to believe this provides the best balance between the projected value of the incremental storage capacity to minimize gas supply costs, the value of reducing gas cost uncertainty and volatility, and the reliability benefits provided by storage capacity, and the fixed cost commitments needed to contract for the storage capacity.

[2] "Assessment of Storage Capacity Requirements for Enbridge Gas In-franchise Bundled Service Customers", October 12, 2022. Page 14

1.3 Structure of Report

The market changes driving the changes in storage cost and value are discussed in Section Two of this Addendum and the updated storage value analysis is reviewed in Section Three. Section Four provides a comparison of the results of the updated analysis to the analysis presented in the October 2022 report. The impact of the updated analysis on the overall conclusions is presented in Section Five.

2 Changes in the North America Gas Market Outlook

This section of the report reviews the changes in natural gas market conditions between Q2 2022 base case and Q4 2023 base case that impact natural gas prices and the value of gas storage for Enbridge Gas, as well as the impact of the change in the analysis time frame from April 2023 through March 2028 to April 2024 through March 2029.

2.1 Overall Impact of Market Changes on the ICF Natural Gas Price Forecast

Outlook for Natural Gas Prices

In the 2022 forecast, ICF was projecting a steady decline in natural gas prices through 2025, followed by a slow increase in prices thereafter. However, prices fell much more rapidly than anticipated in that forecast due to warmer than normal weather conditions that limited storage withdrawals, and a faster than projected market response to the high prices seen in 2022. As a result, the storage analysis period no longer includes three years of falling prices, which acted to hold down storage values in the original analysis.

The ICF Q4 2023 Base Case forecast of mid-term (through 2030) natural gas prices at major market hubs in North America are generally higher than the pricing forecasts produced in Q2 of 2022 (which underpinned the October 2022 Report), resulting in an increase in overall projected natural gas commodity costs for Enbridge Gas customers. Exhibit 2-1 shows a comparison of the monthly prices at Henry Hub from the ICF Q4 2023 Base Case and the ICF Q2 2022 Base Case. Exhibit 2-2 shows the same comparison at Dawn.

Exhibit 2-1 **ICF Forecast of Monthly Prices at Henry Hub (2022$/MMBtu)**

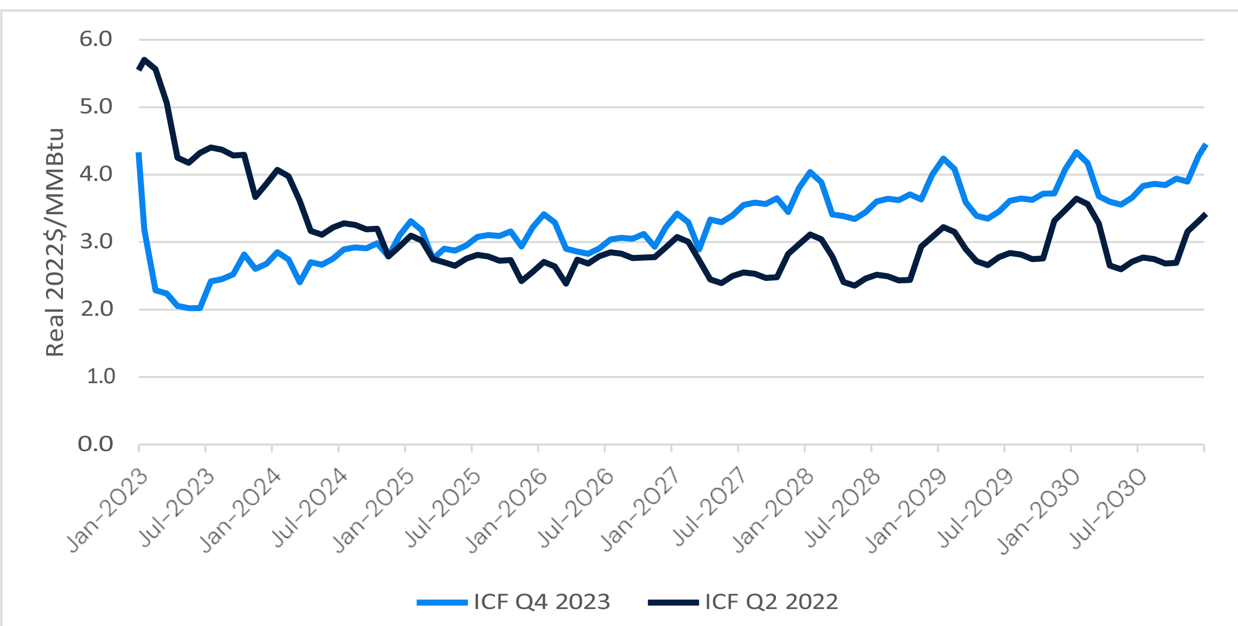
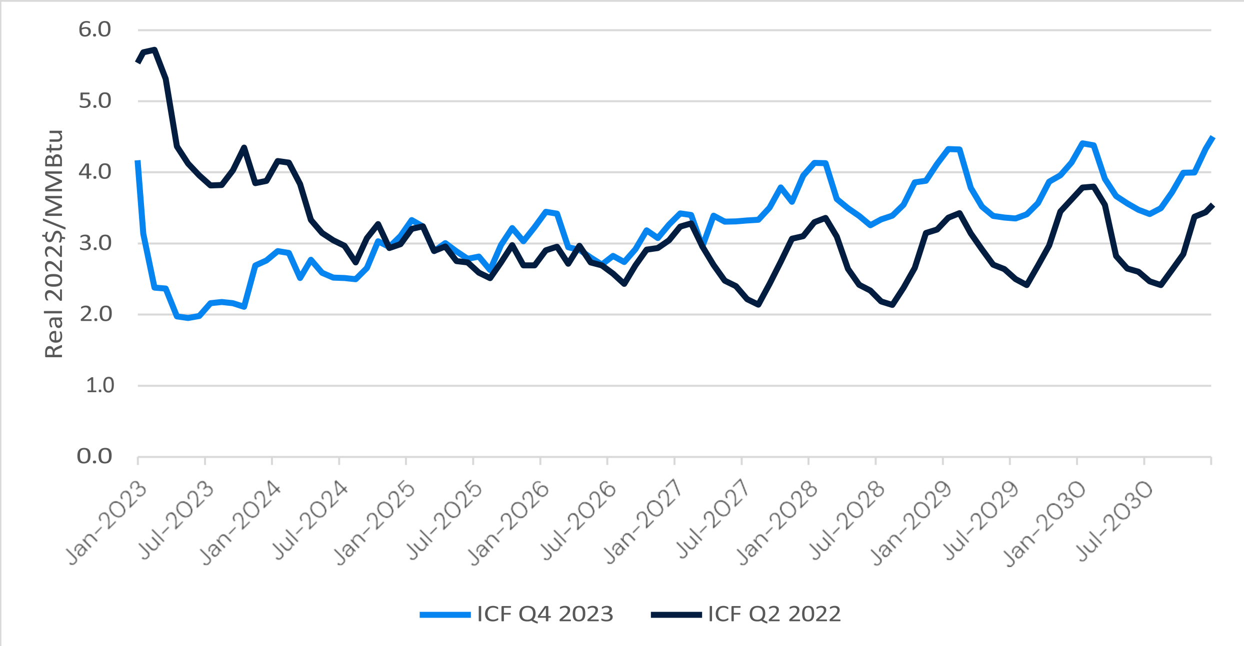


Exhibit 2-2 ICF Forecast of Monthly prices at Dawn (2022$/MMBtu)



Source: ICF GMM®

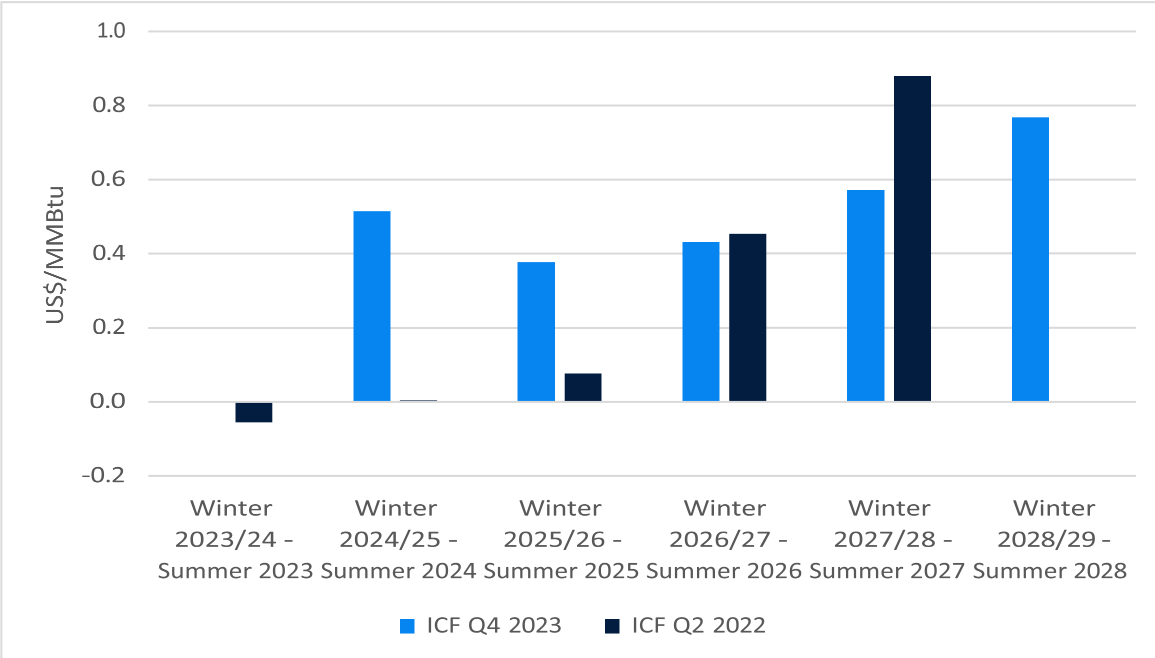
Outlook for Seasonal Price Spreads at Dawn

The costs and the value of market-based storage used by Enbridge Gas to serve bundled service customers are driven by the seasonal changes in natural gas prices.

Exhibit 2-3 illustrates the seasonal gas price spread at Dawn and how it has changed from the October 2022 Report analysis. As per the Q4 2023 base case, seasonal price spreads have increased for Winter 2024/25 relative to the 2024 injection season as the prices for the summer months in 2024 have gone down in the ICF Q4 2023 base case. For the spread between Winter 2027/28 – Summer 2027 as well as Winter 2028/29 – Summer 2028, the spreads are lower compared to the Q2 2022 base case since the average summer month prices increased more compared to the winter month prices between the cases.

Note that the Storage analysis done in October 2022 was based on the 5-year period from April 2023 through March 2028. The updated storage analysis done in February 2024 was based on the 5-year period from April 2024 through March 2029.

Exhibit 2-3 Difference between Winter and Summer prices at Dawn in ICF Q4 2023 base case versus ICF Q2 2022 base case (Nominal US$/MMBtu)



Source: ICF GMM®

A more detailed review of the factors driving the forecast changes in natural gas prices and the differences between summer and winter prices at Dawn is provided below.

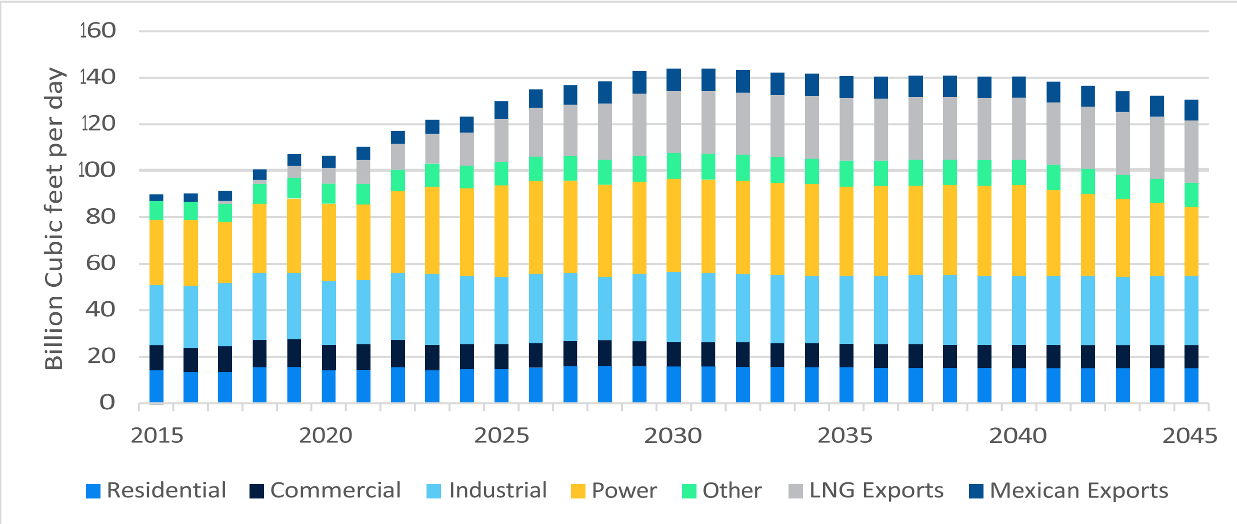
2.2 Changes in the North America Gas Market Outlook

North American Demand Outlook

The Russia-Ukraine conflict as well as the rebound in market activities post-COVID-19 pandemic led to continued growth in gas consumption and gas exports from North America. ICF expects total natural gas demand to grow significantly over the next five to six years with most of the growth resulting from growth in LNG exports[3] and in demand for power generation. Exhibit 2-4 breaks down the total US and Canada demand across different sectors by year as per ICF's Q4 2023 base case.

[3] Currently, all of the LNG facilities brought online prior to 2030 in ICF's base case already have FERC approvals in place. As a result, ICF does not expect the Biden administration's pause on new US LNG export approvals to have any impact on this storage analysis since the impact of this policy change will only be seen after the end of the analysis period for this study, which is 1st April 2029.

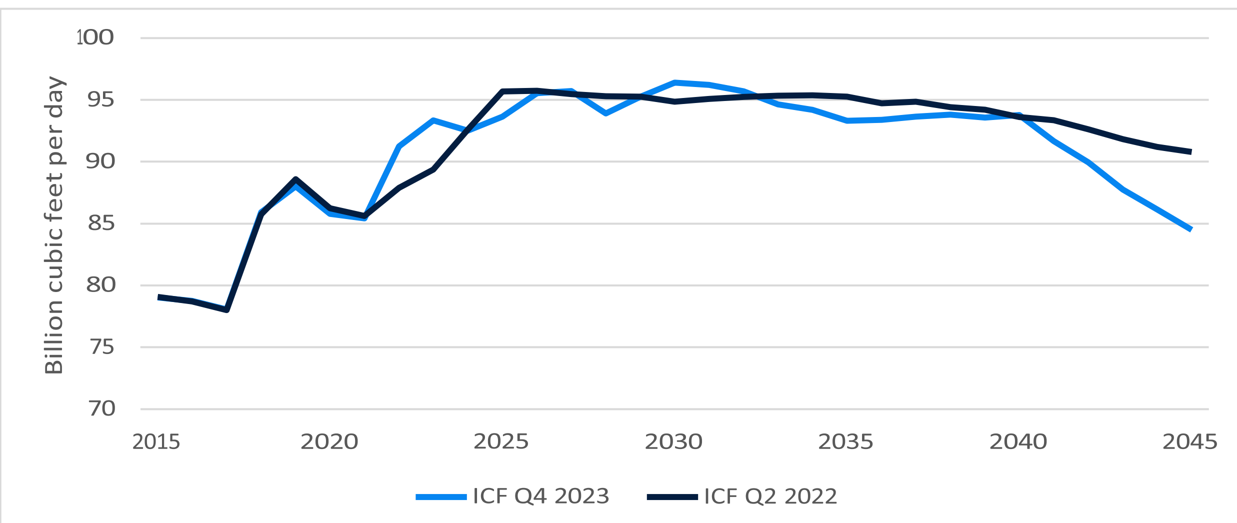
Exhibit 2-4 Total U.S. and Canada Demand by Sector (Bcf/day)



Source: ICF GMM®

Exhibit 2-5 shows the total end-use demand (residential, commercial, industrial, and power sector) between ICF's Q4 2023 base case and the Q2 2022 base case.

Exhibit 2-5 US and Canada end-use Demand (Bcf/day)

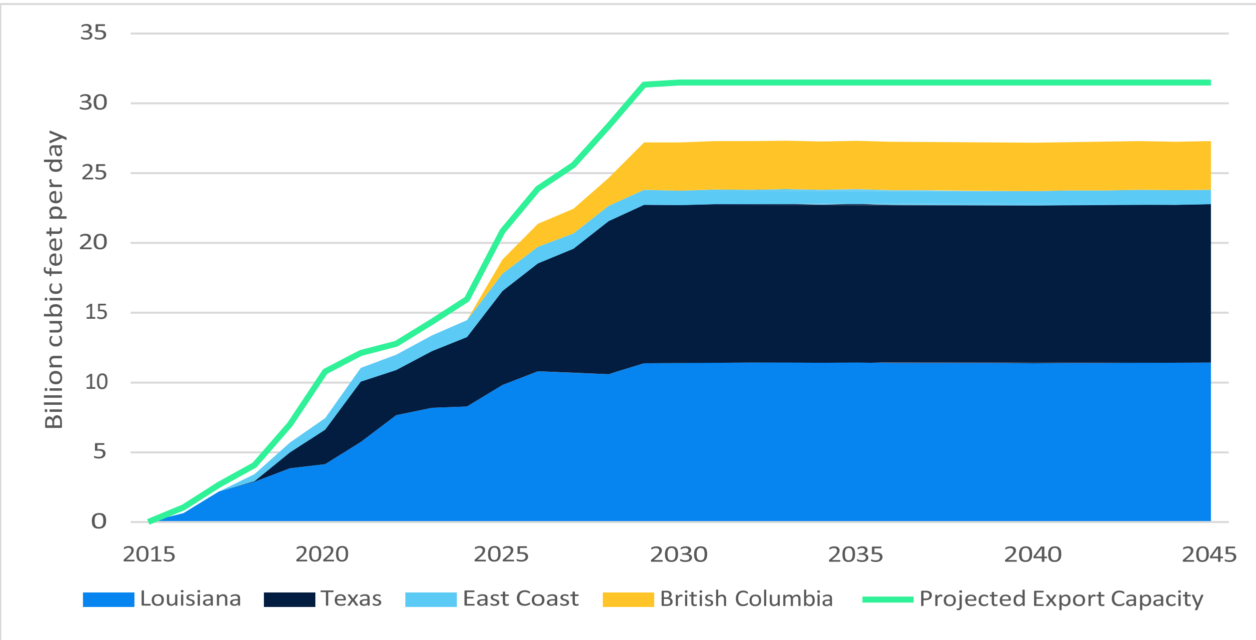


Source: ICF GMM®

Between ICF's Q2 2022 base case and ICF's Q4 2023 base case, the projected level of natural gas demand across North America, during 2023-2030, increased by close to 4.4 Bcfd. This is primarily driven by a 3.8 Bcfd increase in export-based demand coming from the Plaquemines, Port Arthur, Saguaro, and Rio Grande facilities. Driftwood LNG, included in the forecast earlier, has now been removed from the Q4 2023 base case. In the Q4 2023 base case ICF assumed that 15 North American LNG export terminals will be built and/or expanded: Sabine Pass, Freeport, Cove Point, Cameron, Corpus Christi, Elba Island, Golden Pass, LNG Canada Phase 1 & 2, Woodfibre, Calcasieu Pass Phase 1, Plaquemines Phase 1 & 2, and Port Arthur Phase 1, Costa Azul, Saguaro, and Rio Grande.[4]

North American LNG export terminal capacity utilization is projected to average about 88% through 2045, this is down from 93% back in ICF's Q2 2022 base case. Exhibit 2-6 below shows the LNG Export Volumes versus Capacity from ICF's Q4 2023 base case.

Exhibit 2-6 LNG Export Volume versus Capacity (Bcfd)

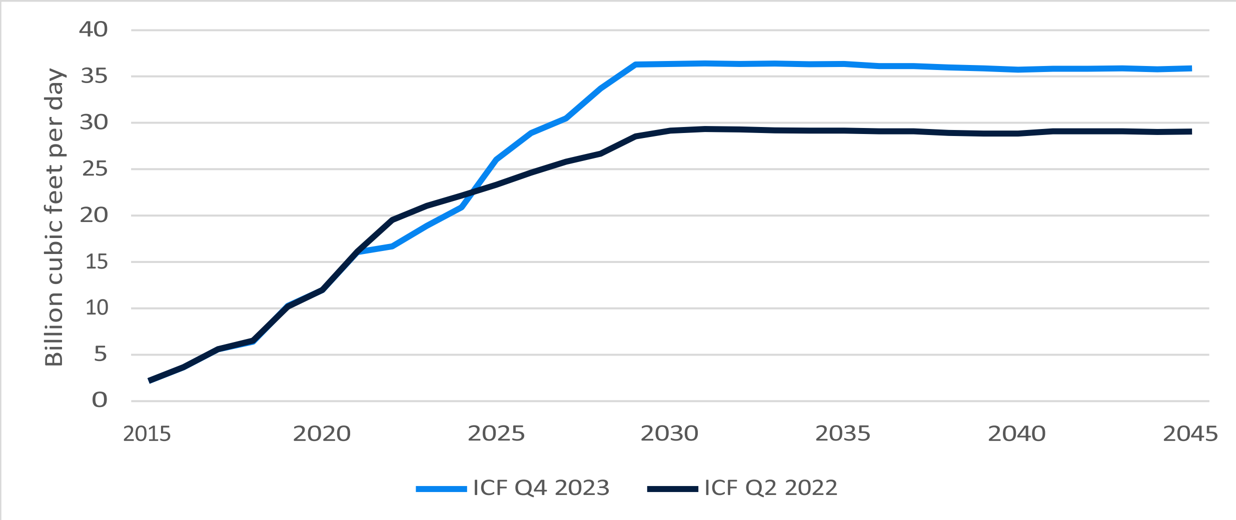


Source: ICF GMM®

US and Canada LNG export-based demand is up by 3.5 Bcfd on average between 2023-2030 in the revised Q4 2023 base case versus the prior Q2 2022 base case. Exhibit 2-7 below depicts the US and Canada Export based demand in the ICF Q4 2023 base case relative to the ICF Q2 2022 base case. The total export-based demand including the exports to Mexico is up by 3.8 Bcfd between the two cases. Higher natural gas exports add an upward pressure on the gas prices.

[4] All trains under Sabine Pass 1 & 2 are now operational and came online between 2017 to 2022. Trains 1-3 of Freeport LNG came online by 2020 while ICF expects train 4 of freeport LNG to be in-service by 2026. Cove Point came into service in 2018 and Cameron LNG in 2020. Three trains of Corpus Christi came online between 2019 to 2021 while the fourth train is expected to be in service by 2026. Elba Island entered in-service in 2020. Golden Pass is expected to be operational between 2024-2025. Calcasieu Pass Phase 1 came online n 2022. ICF expects Plaquemines Phase 1 & 2 to be online by 2026, Port Arthur Phase 1 by 2028, Costa Azul by 2025, Saguaro and Rio Grande by 2028. LNG Canada Phase 1 & 2 is expected to be online in 2024 and 2028 respectively and Woodfibre LNG is expected to be in-service in 2025.

Exhibit 2-7 US and Canada Export based demand (Bcfd)



Source: ICF GMM®

North American Supply Outlook

Over the past several years, natural gas production in the U.S. and Canada has grown quickly. ICF projects production to grow further through 2030 and then expects it to remain flat. ICF expects the production to increase year-over-year by 2.6% in 2024 and 4.0% in 2025 with increasing production efficiencies in the major natural gas basins.

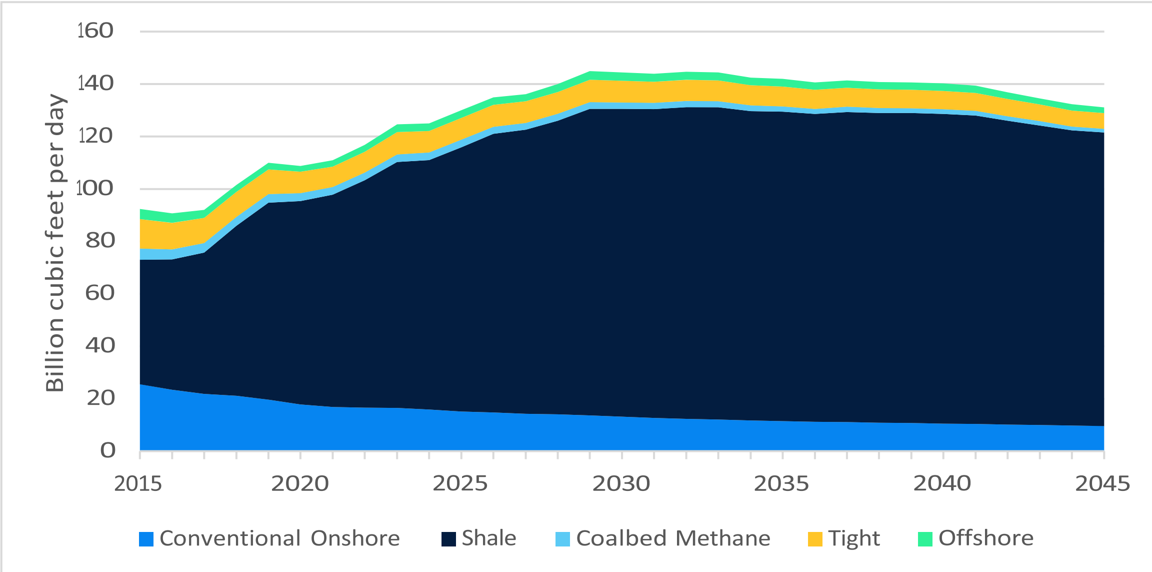
Over 75% of the production growth in U.S. and Canada between 2023 and 2045 comes from the Permian and Haynesville regions in the U.S. Oil-directed drilling activity in the Permian region will account for about 54% of total incremental production growth between 2023 and 2045. Gas-directed drilling activity in the Haynesville region will account for approximately 22% of total incremental production growth between 2023 and 2045. In Canada, incremental production growth will come from shale gas and other unconventional resources.

Even with relatively high oil prices, North American drilling activity has been slower than expected recently as publicly traded upstream corporations have been more cautious about investing capital and expanding drilling operations considering economic, geopolitical, trade and policy uncertainties.

ICF's Q4 2023 base case forecasts 6.5 Bcfd of net growth in gas production between 2023-2045 across North America which is down from 7.7 Bcfd in ICF's Q2 2022 base case. Between 2024-2028, the total production across U.S. and Canada grows by 15.2 Bcfd in the Q4 2023 base case.

Exhibit 2-8 provides the breakdown of the US and Canada Natural Gas Production by type as per ICF's Q4 2023 base case.

Exhibit 2-8 U.S. and Canada Natural Gas Production



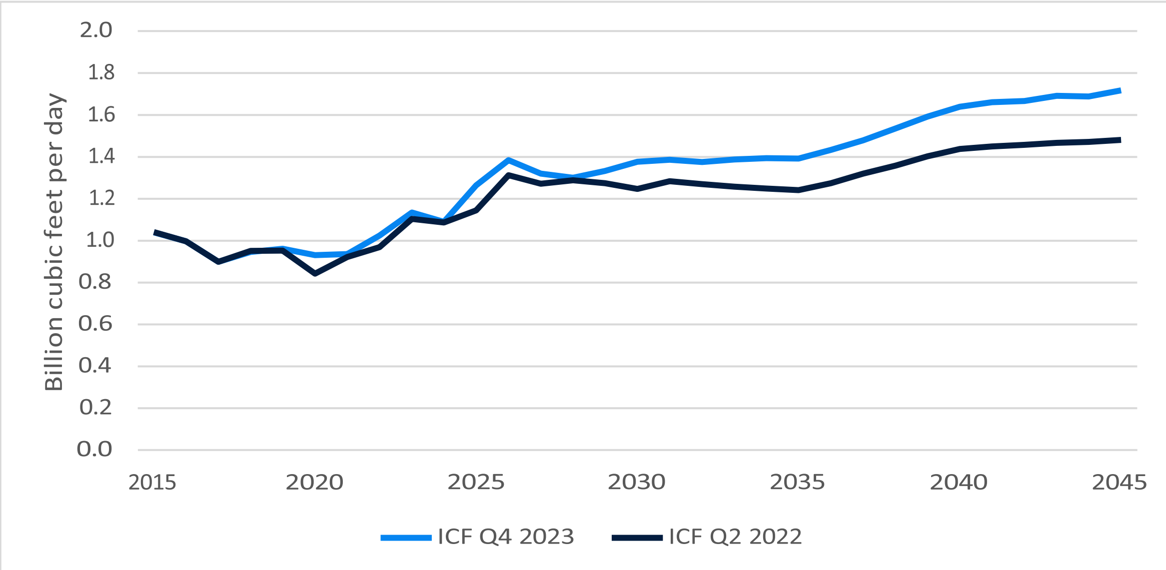
Source: ICF GMM®

2.3 Changes in the Ontario Market Outlook

Ontario Demand Outlook

The gas demand forecast for Ontario in the Q4 base case was updated to reflect the most recent Canada's Energy Regulator (CER) 2023 current measures forecast. In comparison to the Q2 2022 base case, the Q4 2023 base case saw a minor increase in demand in the industrial and power sectors. Between 2024-2028, the industrial and power demand increased by just 50 MMcfd compared to the Q2 2022 base case. The industrial sector along with the power sector account for 53 percent of the total end-use demand for natural gas in Ontario on average between 2023 to 2045 as per the Q4 2023 base case. The combined demand on average is up by 130 MMcfd between 2023 to 2045 compared to the Q2 2022 base case. Exhibit 2-9 provides the natural gas use in the industrial and power sectors in Ontario in both the Q4 2023 and Q2 2022 base case.

Exhibit 2-9 Natural Gas use in the Industrial and Power sectors in Ontario (Bcfd)

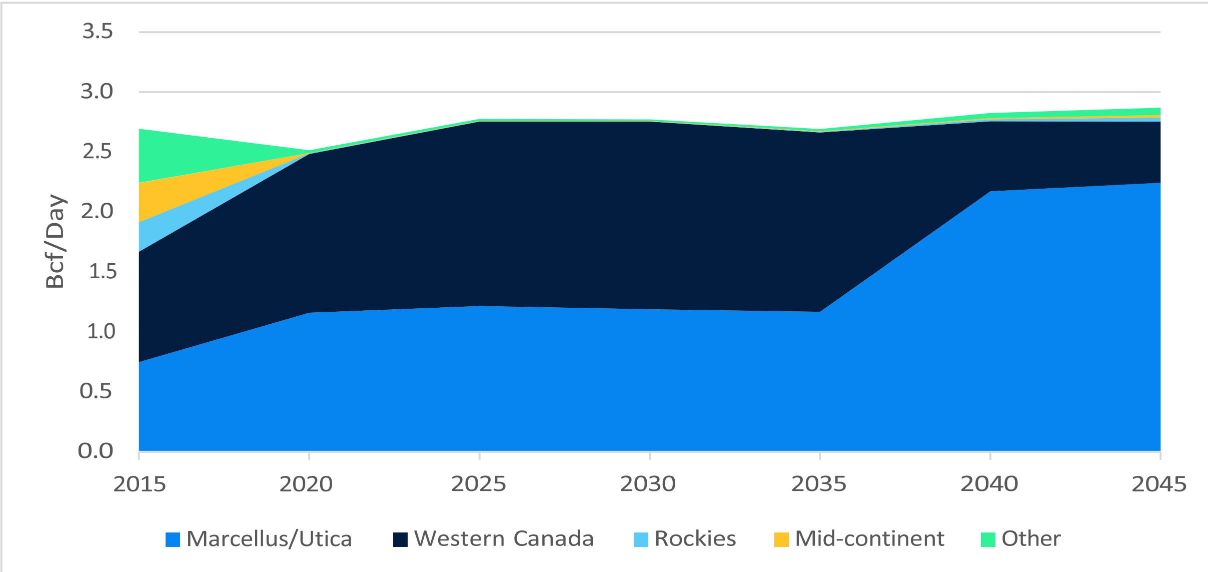


Source: ICF GMM®

Ontario Supply Outlook

Ontario primarily relies on natural gas originating from the Marcellus/Utica basins and Western Canada to meet natural gas demand. Natural gas produced in the Western Canadian Sedimentary Basin is transported to Ontario via major inter-provincial and interstate pipelines including the TC Energy Mainline and the Great Lakes Pipeline. Natural gas produced in Marcellus/Utica basins is transported to Ontario via the Rover, Nexus, Vector, National Fuel, and Empire pipelines. ANR pipeline and Panhandle Eastern also have interconnects with the Enbridge Gas pipeline network and TC Energy pipelines in Ontario. These pipelines bring gas supply into Ontario from the Midcontinent and Rockies. Exhibit 2-10 below shows the gas flows into Ontario from multiple gas supply basins.

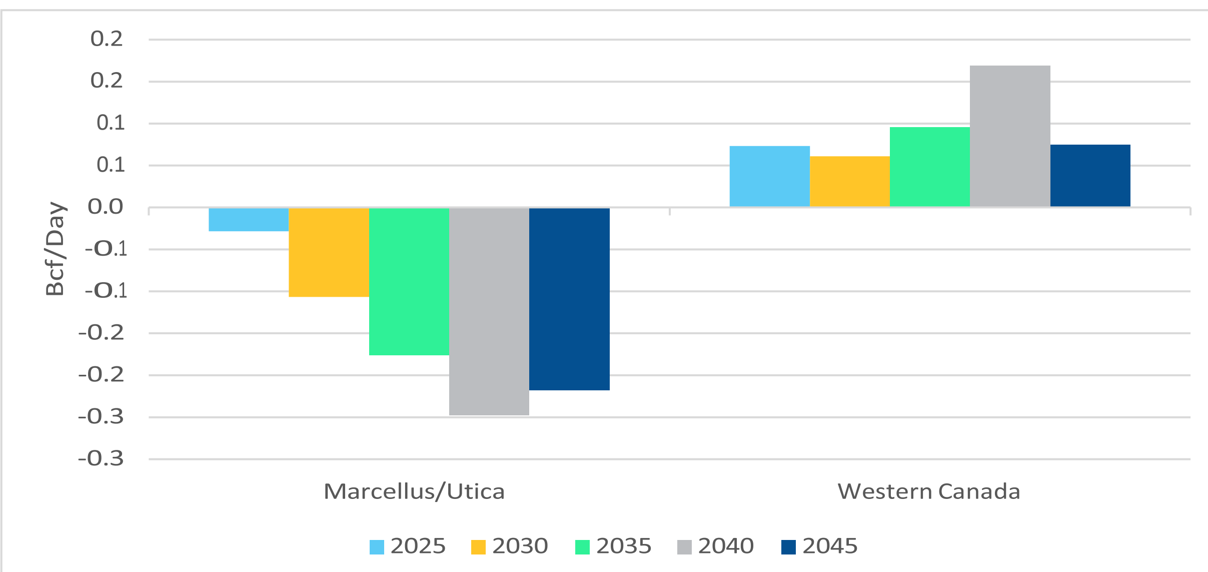
Exhibit 2-10 Gas flows into Ontario (Bcf/d)



Source: ICF GMM®

The Exhibit 2-11 below shows the change in regional supply into Ontario between the latest Q4 2023 case versus the prior Q2 2022 base case. Due to greater LNG export expansions as well as the new Transco pipeline in Q4 2023 base case, more Marcellus and Utica gas is now projected to flow south rather than West and North into Ontario. This leads to a reduction in gas supply from Marcellus/ Utica coming into Ontario. Flows from Western Canada shale increase to support the increasing industrial and power demand in Ontario.

Exhibit 2-11 Change in Ontario Regional Supply between ICF Q4 2023 versus Q2 2022



Source: ICF GMM®

3 Updated Analysis of Storage Value

3.1 Overview of Approach

The updated analysis of storage value was conducted using the same methodology documented in the October 2022 Report. The analysis is based on alternative approaches to assessing storage value applied for a range of different weather sensitivities and a range of alternative storage capacity alternatives.

The updated analysis contained in this Addendum is based on ICF's Q4 2023 base case, as well as updated data on Enbridge Gas storage costs, and other gas portfolio costs, and the value of storage deliverability. The timeframe for the analysis has been shifted by one year to reflect a shift in the analysis start date from April 2023 to April 2024.

Alternative Weather Scenarios Considered

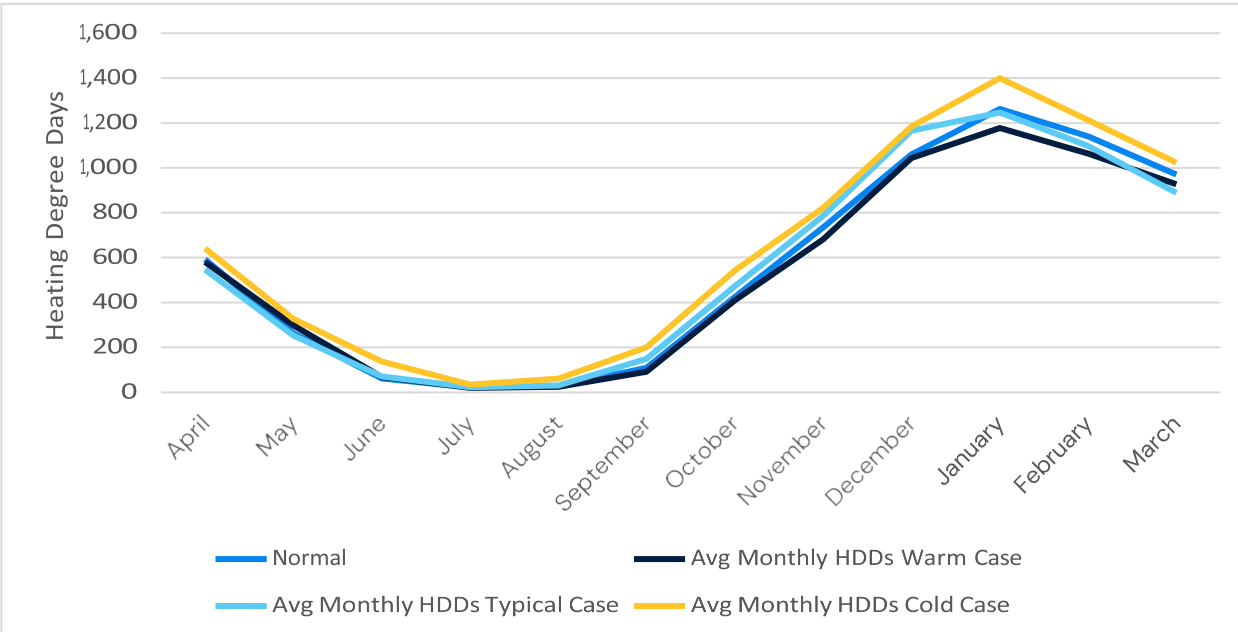
ICF developed a series of alternative weather scenarios to assess the impact of different weather patterns on natural gas markets. These weather scenarios were based on real weather patterns applied to the gas market forecast over a five-year period (April 2024- March 2029). ICF used the same weather patterns used in the 2022 analysis but moved the starting point from April 2023 to April 2024 to develop updated forecasts of natural gas markets reflecting the market changes reviewed in Section 2 of this report.

The Normal Weather scenario is based on the average of the monthly HDD and CDD data for each month over the 20-year period from 2003 to 2022. ICF selected GMM's Q4 base case from November 2023 to define the Normal Weather scenario. The Warmer than Normal Weather scenario reflects an actual five-year weather period where the HDDs were lower than the normal (base) weather conditions. The Typical Weather scenario is based on five years of actual weather that in total was the closest to the Normal Weather scenario. The Colder than Normal Weather scenario is based on five years of actual weather data with HDDs higher than the Normal Weather scenario. The three alternate weather scenarios are summarized below:

- For the Warmer than Normal Weather scenario, ICF selected the warmest 5-year period in Ontario between 1980 to 2022 using the actual monthly HDD data. Based on this approach, 2015 – 2019 turned out to be the case with the lowest HDDs.
- For the Typical Weather scenario, ICF selected the five-year period that overall was closest to the normal weather scenario. Based on this, 2008 – 2012 turned out to be the scenario where the Ontario HDDs were closest to the normal scenario.
- For the Colder than Normal Weather Scenario, ICF selected the coldest 5-year period in Ontario between 1980 to 2022 using the actual monthly HDD data. Based on this approach, 1981 – 1985 turned out to be the case with the highest HDDs.

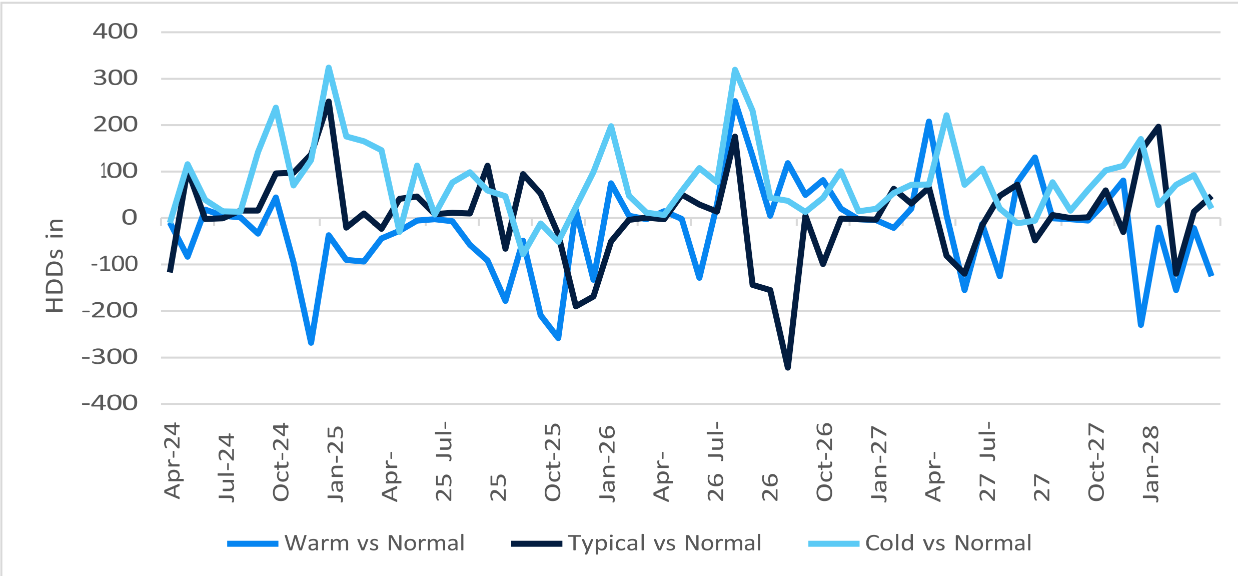
Exhibit 3-1 below provides the average HDDs in Ontario between April 2024 to March 2029 across the normal and alternative weather cases. The weather scenarios reflect actual weather patterns over a five-year period. The colder than normal scenario is colder on average than the normal weather scenario but is not colder during every month of the analysis and the warmer than normal scenario is warmer on average than the normal weather scenario but is not warmer during every month of the analysis. The typical weather scenario is very similar to the normal weather scenario over the five-year analysis period but is colder than normal during some years and warmer than normal during other years.

Exhibit 3-1 Average HDDs in Ontario between April 2024 to March 2029 between the alternate weather cases and normal case



Source: ICF GMM®

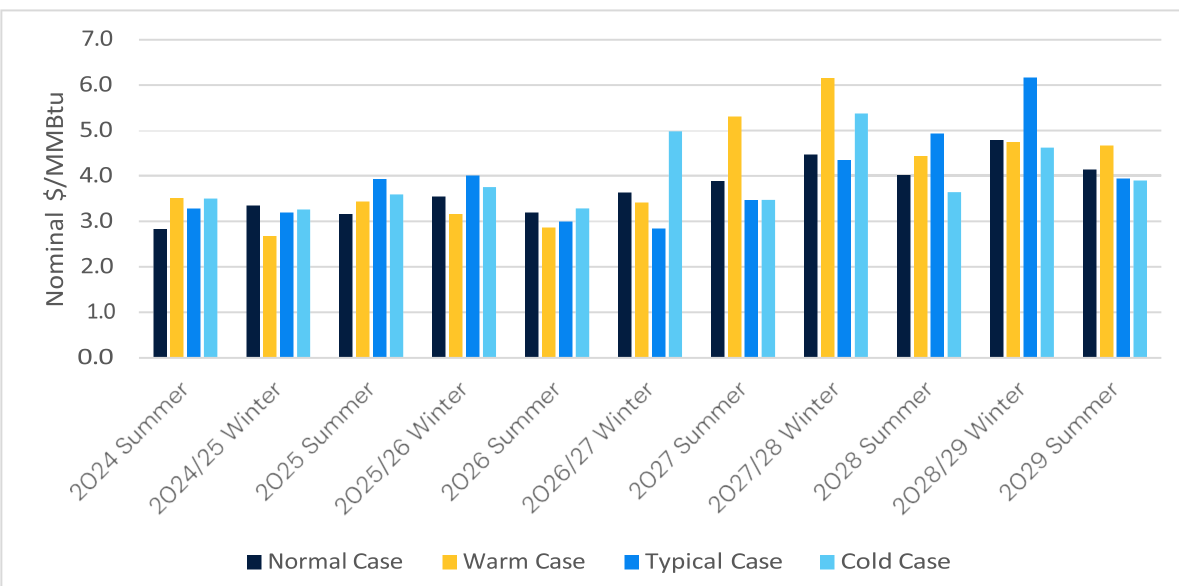
Exhibit 3-2 Variation in the HDDs in Ontario between the alternate cases and the normal case



Source: ICF GMM®

Exhibit 3-2 above shows the change in the Ontario HDDs between the alternative cases and the normal weather case. Exhibit 3-3 below depicts prices at Dawn across the four scenarios during the study period April 2024 to March 2029. The three alternate weather cases which are based on actual weather show significant variation in year-to-year price patterns. Since ICF assumes all the other assumptions to be consistent across the four cases, the change in prices at Dawn is strictly driven by different weather assumptions which in turn impact the demand conditions.

Exhibit 3-3 Dawn Prices (Nominal US$) under the Four Enbridge Gas Weather Scenarios



Source: ICF GMM®

Alternative Storage Capacity Options

For the updated ICF Base Case market forecast and for each of the ICF gas market forecast sensitivities based on alternative weather scenarios, ICF requested that Enbridge Gas perform a set of alternative portfolio analyses to assess the value of storage capacity in the Enbridge Gas supply portfolios. Enbridge Gas used their gas supply planning model (Supply Planning Model) to conduct this analysis. The analysis uses a base gas supply portfolio with storage capacity set at the level determined by the Aggregate Excess methodology. The analysis is underpinned by Enbridge Gas's demand forecast[5], and Enbridge Gas's upstream contract costs.

The alternative storage capacity scenarios evaluated included:

1. **Reduced Storage Capacity Analysis** – ICF evaluated a supply plan based on a minimum storage capacity 5 PJ lower than the level suggested by the Aggregate Excess methodology for each of the four weather scenarios. The purpose of this analysis was to evaluate the impact on total portfolio costs of holding less storage than the amount identified using the Aggregate Excess methodology and using an alternative approach to meeting supply portfolio requirements. The results of this analysis continue to indicate that storage capacity provides a more cost-effective supply solution than non-storage options.

2. **Resource Mix Optimization Analysis** – ICF requested that Enbridge Gas use the gas supply planning model to determine the amount of storage capacity resulting in the lowest overall supply portfolio cost given the fixed gas supply commitments for each year of the analysis for each of the four weather scenarios. ICF used the results of the Enbridge Gas's gas supply planning model analysis to evaluate the impact of changes in storage capacity for the Base (or Normal Weather) case and for each of the three alternative weather scenarios to determine the potential costs and benefits of optimizing the amount of storage capacity used by Enbridge Gas on a year-to-year basis relative to the currently contracted level of storage capacity.

3. **Fixed Storage Capacity Analysis** – In the Resource Mix Optimization Analysis, the Enbridge Gas Supply Model selected the optimum storage capacity in each year and operated the storage system according to the amount of storage selected. This analysis suggested that incremental storage capacity would provide value to Enbridge Gas in-franchise bundled service customers. In order to validate the results of the analysis, ICF requested that Enbridge Gas run their Supply Planning Model analysis with fixed amounts of incremental storage capacity for the Typical Weather Scenario over the 5-year planning period. The 5 PJ, 8 PJ, 10 PJ and 20 PJ amounts evaluated in this analysis were unchanged from the amounts evaluated in the October 2022 Report.

[5] Phase 1 Exhibit 4.2.1, Table 1

3.2 Impact of Reducing Storage Capacity on Enbridge Gas's Supply Portfolio Value

One of the questions that Enbridge Gas asked ICF to address in the previous analysis was whether there were viable market-based alternatives to the market-based storage capacity, and whether these alternatives would allow Enbridge Gas to hold less market-based storage capacity to serve bundled service customers. In the original analysis ICF concluded that there could be viable market-based alternatives to market-based storage capacity, but these alternatives would not be preferable to market-based storage capacity due to a combination of factors including economics, system reliability impacts including contributions to design day capacity planning, and increases in supply cost volatility to consumers. In the October 2022 Report, ICF considered two broad alternatives to the use of market-based storage capacity in the bundled service customer supply portfolio. The first approach was to hold additional pipeline capacity to serve the load served by the market-based storage. This review concluded that incremental pipeline capacity would not be an economic alternative to market-based storage. ICF monitors natural gas market conditions and changes on a continuing basis. During the course of this process, ICF has not identified any fundamental market changes since the initial report was prepared that would change this assessment.

The second alternative considered by ICF was the substitution of incremental purchases at Dawn for winter storage withdrawals, combined with winter peaking service to offset the storage contributions to design day. The October 2022 Report concluded that reducing storage would increase overall supply costs based on a projection of the impact of reducing capacity by 5 PJ from 203 PJ to 198 PJ. ICF updated this analysis to determine if the recent changes in the market would result in a different conclusion. The updated analysis included the impacts on gas supply purchases, gas storage costs, gas pipeline transportation costs, and the cost of replacing the deliverability lost with the reduction in storage capacity.

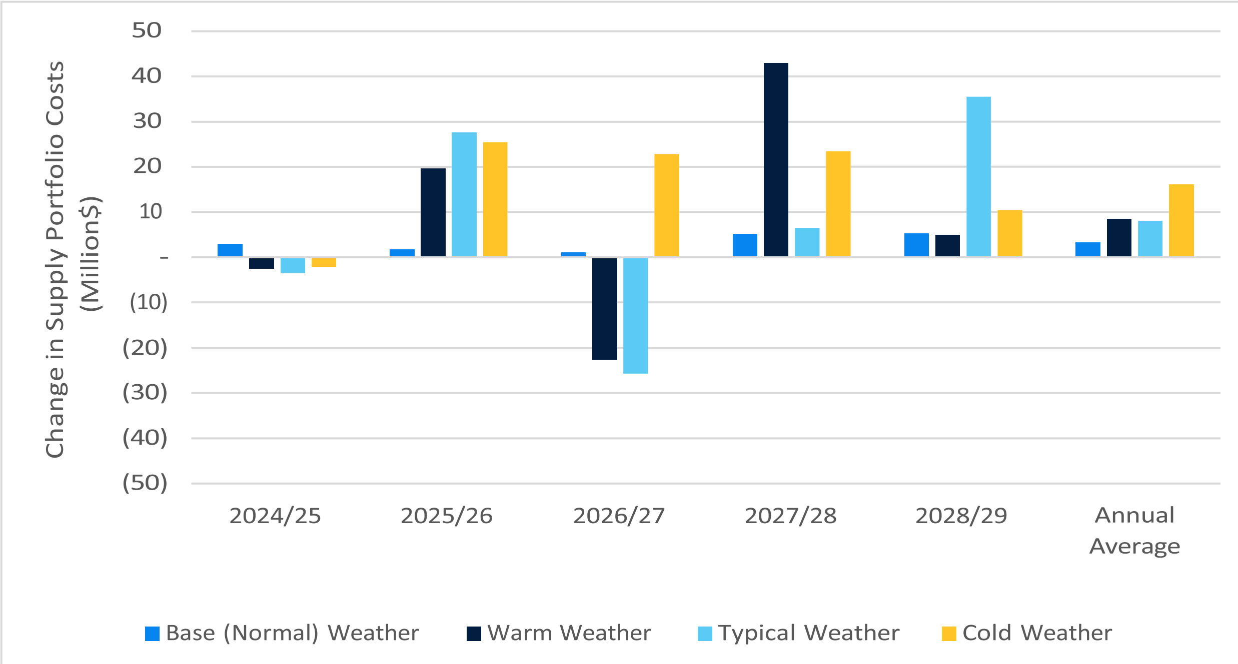
To assess the impact on the supply portfolio of reducing storage capacity, Enbridge Gas ran the Supply Model with a 5 PJ decrement relative to the amount of storage capacity indicated by the Aggregate Excess methodology for 2023 for each of the four weather scenarios evaluated. ICF then estimated the cost of replacing the incremental deliverability lost with the reduction in storage capacity.[6]

The results of the analysis indicate that reducing storage capacity below the level indicated by the Aggregate Excess methodology would result in reduced expenditures on natural gas storage. However, the storage demand charge savings are more than offset by the increased cost of purchasing gas supply in the winter months and the cost of replacing peak day deliverability.

Exhibit 3-4 below depicts the impact of reducing the storage capacity by 5PJ on the total supply portfolio costs.

[6] The calculation of the cost of replacing lost deliverability is documented in Appendix A.

Exhibit 3-4 Impact of 5 PJ decrement in storage capacity on the total supply portfolio costs (Million $)



The annual average portfolio costs were higher with reduced storage capacity, in line with the prior analysis done in April 2022. The impact on supply portfolio cost associated with reducing storage capacity below the level identified by the aggregate excess methodology was greater in the updated analysis than in the previous analysis for all four of the weather scenarios. As illustrated in Exhibit 3-5, decreasing storage by 5 PJ results in average annual portfolio cost increases from a range of $3.2 million to $16.0 million, depending on the weather scenario being evaluated.

Exhibit 3-5 Impact of a 5 PJ Reduction in Storage Capacity on Gas Supply Portfolio Costs

Impact of Reduction in Storage Capacity on Gas Supply Portfolio Cost							
(CAD$Millions)	2024/25	2025/26	2026/27	2027/28	2028/29	Annual Average – Updated	Annual Average - Oct 2022
Supply Model Portfolio Costs – Base Case Storage Capacity							
Normal Weather	2,452	2,694	2,724	3,299	3,442	2,922	2,671
Warmer than Normal Weather	2,374	2,619	2,618	4,192	3,544	3,069	2,889
Typical Weather	2,604	2,967	2,448	3,048	4,118	3,037	2,556
Colder than Normal Weather	2,646	2,816	3,212	3,432	3,222	3,066	2,711
Supply Model Portfolio Costs – 5 PJ Reduction in Storage Capacity							
Normal Weather	2,453	2,694	2,723	3,302	3,445	2,923	2,670
Warm Weather	2,369	2,636	2,593	4,233	3,546	3,076	2,890
Typical Weather	2,599	2,993	2,420	3,053	4,151	3,043	2,555
Cold Weather	2,641	2,840	3,233	3,454	3,231	3,080	2,720
Cost of Replacing Lost Deliverability	2.15	2.15	2.15	2.15	2.15	2.15	2.05
Impact of Reduced Storage Capacity on Portfolio Cost							
Normal Weather	2.9	1.8	1.1	5.2	5.3	3.2	0.24
Warm Weather	(2.5)	19.6	(22.6)	43.0	4.9	8.5	2.64
Typical Weather	(3.5)	27.5	(25.7)	6.5	35.5	8.1	0.87
Cold Weather	(2.1)	25.5	22.8	23.5	10.5	16.0	10.96

3.3 Optimized Storage Capacity for Different Weather Scenarios

Given the increase in gas supply portfolio costs resulting from a reduction in storage capacity below the level indicated by the Aggregate Excess methodology ICF proceeded to evaluate the impact of increasing storage capacity above this level. ICF requested that Enbridge Gas use the Gas Supply Planning model to determine the optimum level of storage capacity for each year of the five-year analysis period for each of the four weather scenarios. The optimum level of storage capacity was determined by optimizing for the lowest gas supply portfolio cost consistent with existing infrastructure and contractual agreements, and Enbridge Gas supply requirements.

Each scenario started with 203 PJ of storage capacity under contract and included three additional tranches of storage capacity with storage costs increasing for each tranche:

- The first tranche of incremental storage included 10 PJ of storage capacity at a rate of $1.28 per GJ of capacity.

- The second tranche included an additional 10 PJ of storage capacity at a rate of $1.38 per GJ.
- The third tranche included an additional 10 GJ of storage capacity at a rate of $1.48 per GJ.

The cost of each tranche of additional storage was provided by Enbridge Gas. The first tranche reflects recent storage offers to Enbridge Gas. The incremental costs added to the cost of the first tranche used to derive the storage costs for the second and third tranche were unchanged from the analysis in the October 2022 Report. As in the October 2022 Report, the maximum amount of market base storage capacity that could be selected beyond the amount determined by aggregate excess was 30 PJ.

Under normal weather conditions, the Gas Supply Planning model selected incremental storage capacity in the solution in one out of the five years evaluated. The Typical Weather scenario was optimized with additional storage in three out of five years, the Warm Weather scenario was optimized with additional storage capacity in two out of the five years, and the Cold Weather scenario was optimized with additional storage in four out of five years. Exhibit 3-6 below breaks down the total existing and incremental storage capacity in each of the weather scenarios by year.

Exhibit 3-6 Total Existing and incremental storage (PJ) in each of the weather scenarios by year

Optimized Storage capacity					
CAD$Millions)	2024/25	2025/26	2026/27	2027/28	2028/29
Aggregate Excess Storage Capacity					
Normal Weather	203	203	203	203	203
Warm Weather Case	203	203	203	203	203
Typical Weather Case	203	203	203	203	203
Cold Weather Case	203	203	203	203	203
Incremental Storage Capacity					
Normal Weather	0.0	0.0	0.0	0.0	2.7
Warm Weather Case	0.0	0.0	9.9	30.0	0.0
Typical Weather Case	1.2	0.0	0.0	12.3	30.0
Cold Weather Case	0.0	19.2	30.0	25.3	7.9
Total Optimized Storage Capacity					
Normal Weather	203	203	203	203	206
Warm Weather Case	203	203	213	233	203
Typical Weather Case	204	203	203	215	233
Cold Weather Case	203	222	233	228	211

The total supply portfolio costs for the optimized storage capacity case for all the four weather scenarios is provided in Exhibit 3-7 below. Compared to the October 2022 analysis, the total annual average costs over the 5-year period have increased across all the four weather scenarios.

Exhibit 3-7 Total Supply Costs (Million$) by year between the weather scenarios

Total annual costs (Million$)	2024	2025	2026	2027	2028	Annual Avg – Updated	*Annual Avg – Oct 2022*
Normal Weather Scenario	2,452	2,694	2,724	3,299	3,441	2,922	2,671
Warm Weather Scenario	2,374	2,627	2,666	4,107	3,544	3,063	2,882
Typical Weather Scenario	2,606	2,961	2,499	3,171	3,924	3,032	2,551
Cold Weather Scenario	2,734	2,762	3,106	3,391	3,215	3,042	2,677

These total supply portfolio costs can be broken down by Storage cost, Supply cost, and Transportation cost as provided by Enbridge Gas in their Gas Supply Planning model results.

The incremental costs due to the optimized storage capacity cases are shown in the Exhibit 3-8 to Exhibit 3-11 below.

Exhibit 3-8 provides the incremental storage costs in the optimized storage scenario relative to the scenario where storage capacity is fixed at the aggregate excess level for each year across the four weather scenarios. The incremental storage costs include both storage operating and storage capacity costs. As shown below, the annual average incremental storage costs were lower in the normal and warm weather scenarios but higher in the Typical and cold weather scenarios in the updated analysis when compared to the analysis done in the October 2022 Report.

Exhibit 3-8 Incremental Storage Costs (Million$) by year between the weather scenarios

Incremental storage costs (Million$)	2024	2025	2026	2027	2028	Annual Avg – Updated	*Annual Avg – Oct 2022*
Normal Weather Scenario	0.0	(0.0)	0.0	(0.0)	4.2	0.8	*2.1*
Warm Weather Scenario	(0.0)	0.1	15.3	47.0	(0.1)	12.5	*12.9*
Typical Weather Scenario	1.8	(0.0)	0.8	19.4	47.9	13.9	*9.1*
Cold Weather Scenario	1.0	29.3	46.7	39.0	12.0	25.6	*9.4*

Exhibit 3-9 provides the incremental supply costs in the optimized storage scenario relative to the scenario where storage capacity is fixed at the aggregate excess level for each year across the four weather scenarios. As shown below, the annual average incremental supply costs came down across all the four scenarios. The magnitude of reduction of the supply costs were lower in the normal and warm weather scenarios but higher in the typical and cold weather scenarios in the updated analysis when compared to the analysis done in the October 2022 Report.

Exhibit 3-9 Incremental Supply Costs (Million$) by year between the weather scenarios

Incremental supply costs (Million$)	2024	2025	2026	2027	2028	Annual Avg – Updated	*Annual Avg – Oct 2022*
Normal Weather Scenario	-	-	-	-	(4.9)	(1.0)	*(3.2)*
Warm Weather Scenario	-	8.0	31.9	(132.5)	-	(18.5)	*(20.9)*
Typical Weather Scenario	(0.0)	(5.6)	50.5	103.5	(240.4)	(18.4)	*(14.7)*
Cold Weather Scenario	87.3	(83.4)	(154.1)	(81.1)	(18.5)	(50.0)	*(44.5)*

Exhibit 3-10 provides the incremental transportation costs in the optimized storage scenario relative to the scenario where storage capacity is fixed at the aggregate excess level for each year across the four weather scenarios. As shown below, the annual average incremental transportation costs are lower across all the four scenarios in the updated analysis when compared to the analysis done in the October 2022 Report.

Exhibit 3-10 Incremental Transportation Costs (Million$) by year between the weather scenarios

Incremental Transportation costs (Million$)	2024	2025	2026	2027	2028	Annual Avg – Updated	*Annual Avg – Oct 2022*
Normal Weather Scenario	-	-	-	-	0.3	0.1	*0.7*
Warm Weather Scenario	-	-	1.1	0.4	-	0.3	*0.8*
Typical Weather Scenario	0.0	(0.7)	-	0.0	(0.9)	(0.3)	*0.6*
Cold Weather Scenario	-	-	1.2	1.2	(0.5)	0.4	*1.5*

Exhibit 3-11 provides the incremental total supply costs in the optimized storage scenario relative to the scenario where storage capacity is fixed at the aggregate excess level for each year across the four weather scenarios. As shown below, the annual average incremental total supply portfolio costs are less favorable across all the four scenarios in the updated analysis when compared to the analysis done in the October 2022 Report. This is the result of the optimization selecting a higher level of incremental storage capacity during the peak storage year. Given that we are adding the cost of this incremental storage capacity for the other four years and that storage costs are higher in the updated analysis, the ability of the incremental storage to mitigate cost increases is more limited in the updated analysis compared to the October 2022 report, and overall portfolio cost savings are less.

Exhibit 3-11 Incremental Total Supply Costs (Million$) by year between the weather scenarios

Incremental Total Supply Portfolio costs (Million$)	2024	2025	2026	2027	2028	Annual Avg – Updated	*Annual Avg – Oct 2022*
Normal Weather Scenario	0.0	(0.0)	0.0	(0.0)	(0.4)	(0.08)	*(0.43)*
Warm Weather Scenario	(0.0)	8.1	48.2	(85.1)	(0.1)	(5.76)	*(7.29)*
Typical Weather Scenario	1.7	(6.4)	51.2	122.9	(193.4)	(4.79)	*(4.97)*
Cold Weather Scenario	88.3	(54.2)	(106.1)	(40.9)	(7.1)	(24.0)	*(33.61)*

In all the scenarios, the increase in storage capacity allows Enbridge Gas to purchase additional lower cost natural gas supply during off-peak periods for use during the winter when prices typically are higher. Exhibit 3-12 illustrates the impact of the increase in storage capacity on Enbridge Gas supply portfolio costs for these weather scenarios.

Exhibit 3-12 Average Annual Impact of Incremental Storage Capacity on Enbridge Gas Supply Portfolio Costs (Million CAD$)

(CAD$Millions)	Normal Weather Scenario	Warmer Weather Scenario	Typical Weather Scenario	Cold Weather Scenario
Total Supply Portfolio Costs				
Existing Storage Capacity	2,922	3,069	3,037	3,066
Incremental Storage Capacity	2,922	3,063	3,032	3,042
Gas Supply Costs				
Existing Storage Capacity	2,295	2,442	2,410	2,442
Incremental Storage Capacity	2,294	2,423	2,392	2,392
Storage Costs				
Existing Storage Capacity	34	36	35	32
Incremental Storage Capacity	35	49	49	57
Transport Costs				
Existing Storage Capacity	593	591	592	592
Incremental Storage Capacity	593	592	592	593

These results would imply that the optimal amount of storage capacity held in the Enbridge Gas supply portfolio should vary from year to year between 203 PJ and 233 PJ (or greater) based on weather and market conditions. However, the storage market does not operate in a world with perfect foresight into weather and gas market conditions.

As a result, the optimized analysis is likely to provide a ceiling on the amount of capacity that should be considered in the utility supply portfolio rather than the appropriate level that should be contracted. In the October 2022 analysis, ICF extended the optimized analysis to evaluate the potential impacts of fixing the storage capacity at the highest single year level across all years of the analysis in order to provide insight into the development of the fixed storage capacity analysis discussed in section four (Impact of Different Weather Patterns on Storage Capacity) of the October 2022 analysis. Since this analysis did not play a role in the conclusions, and for simplicity and for consistency between the analysis, this step was not taken in the updated analysis. Instead ICF moved directly to the assessment of the impact of incremental fixed storage capacity on supply portfolio costs in section 3.4 below.

3.4 Impact of Incremental Fixed Storage Capacity on Supply Portfolio Costs for the Typical weather scenario

The optimized storage capacity analysis indicates that holding additional storage capacity above the level identified by the Aggregate Excess methodology should be expected to reduce average gas portfolio costs but does not identify the optimum amount of storage capacity that should be held over a five-year period.

To assess the appropriate amount of incremental storage capacity more accurately, ICF evaluated a range of specific storage capacity levels between the level identified by the aggregate excess approach and the maximum level identified by in the optimized storage capacity analysis. For the updated analysis, ICF requested that Enbridge Gas use the Gas Supply Planning model to evaluate the typical weather scenario using different levels of incremental storage capacity, including 5 PJ, 8 PJ, 10 PJ and 20 PJ above the level indicated by the aggregate excess methodology.[7] For consistency and clarity, these increments were unchanged from the increments used in October 2022 analysis.

Since the normal weather scenario reflects the average weather patterns over a 20-year period from 2003-2022, it underestimates the volatility associated with actual weather. The use of actual weather allows for a more complete assessment of the actual range of impacts due to the range of positive and negative correlations between the weather patterns of different regions across North America. Thus, consistent with the October 2022 analysis, ICF based the Fixed Storage Capacity Analysis for this report on the typical weather scenario rather than the Normal Weather scenario since the typical weather case provides a better representation of how weather conditions impact price volatility and drive storage value.

The analysis also illustrates the impact of the adjustments for the value of deliverability based on the delivered services costs and the ability to minimize gas purchases during the highest price periods.

- Contribution of Storage Deliverability to Design Day Capacity Requirements. Storage deliverability contributes to design day system capacity requirements. In the Gas Supply Planning model analysis, changes in storage capacity are addressed through incremental purchases at Dawn. However, purchases at Dawn do not have the degree of reliability provided by storage deliverability. The difference in reliability provides significant economic benefit to the use of incremental storage that is not captured in the Gas Supply Planning model analysis.
- Contribution Value of Daily Gas Supply Purchasing Flexibility. Storage capacity allows for a more flexible gas purchasing approach that allows the utility to shift purchases on high priced days to purchases on lower priced days. This provides a direct economic benefit to the use of storage that is not captured in the use of storage to address aggregate excess requirements, or through the use of monthly average prices.

This analysis estimates the costs and benefits of holding these different levels of incremental storage capacity over the 5-year period, and more closely resembles how a utility would contract for and use storage capacity relative to the resource optimization analysis.

Exhibit 3-13 represents the impact of different fixed storage capacity contracts for the Typical Weather scenario.

[7] The October Report included the results of a Resource Mix Optimization analysis for the Typical weather scenario but did not include similar analysis for the other weather scenarios. The updated analysis was extended to include all of the weather scenarios. The results from the additional analyses have been included in Appendix B.

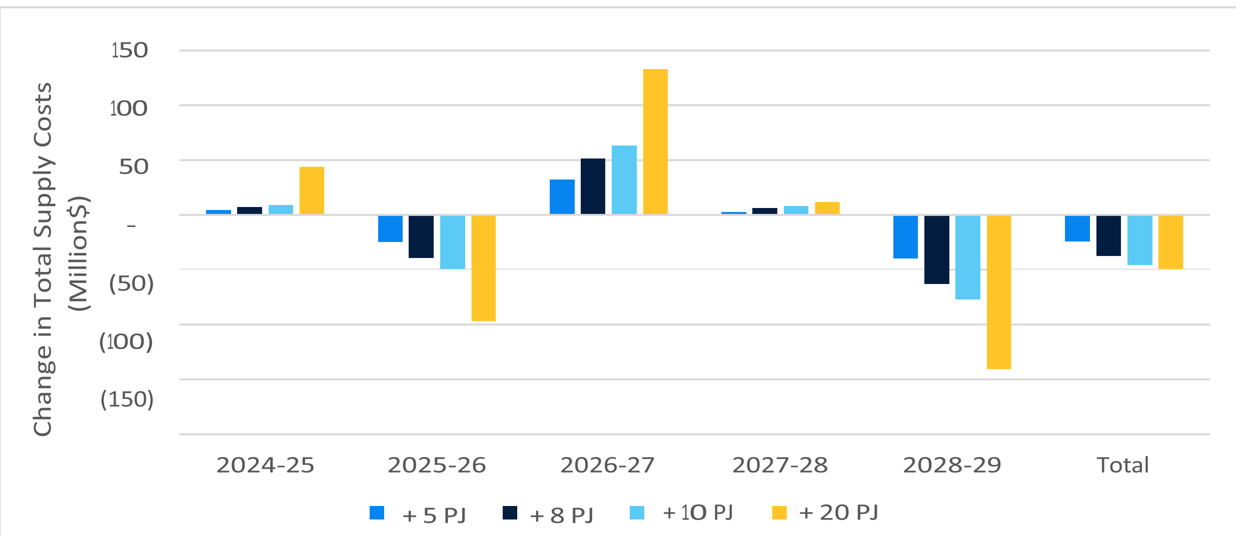
Exhibit 3-13 Impact of Different levels of Storage Capacity on the Total Supply Costs for the Typical Weather Scenario (Million$)

Total Supply Costs with Different Levels of Storage Capacity for the Typical Weather Scenario (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	2,604	2,611	2,616	2,619	2,659
2025-26	2,967	2,945	2,932	2,924	2,881
2026-27	2,448	2,483	2,503	2,517	2,591
2027-28	3,048	3,054	3,059	3,062	3,071
2028-29	4,118	4,081	4,059	4,046	3,988
2024-2029	15,185	15,175	15,169	15,167	15,190
Incremental Supply Costs with Different Levels of Storage Capacity for the Typical Weather Scenario (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	-	7.2	11.5	14.4	54.6
2025-26	-	(21.9)	(34.9)	(43.6)	(86.1)
2026-27	-	35.1	55.7	68.9	143.7
2027-28	-	5.4	10.6	13.4	22.6
2028-29	-	(36.7)	(58.9)	(71.8)	(129.9)
2024-2029	-	(10.9)	(16.0)	(18.7)	4.8
Percentage Change in Costs		**-0.072%**	**-0.105%**	**-0.123%**	**0.032%**
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
Value of Incremental Deliverability	-	2.1	3.4	4.3	8.6
Reduction in Gas Purchase Costs	-	0.6	0.9	1.1	2.3
Total Supply Costs with Different Levels of Storage Capacity for the Typical Weather Scenario					
With Adjustment for Value of Incremental Deliverability (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	2,604	2,609	2,611	2,613	2,648
2025-26	2,967	2,943	2,928	2,918	2,870
2026-27	2,448	2,480	2,499	2,511	2,581
2027-28	3,048	3,051	3,055	3,056	3,060
2028-29	4,118	4,078	4,055	4,041	3,977
2024-2029	15,185	15,161	15,148	15,140	15,136

Incremental Supply Costs with Different Levels of Storage Capacity for the Typical Weather Scenario (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	-	4.5	7.2	9.0	43.8
2025-26	-	(24.6)	(39.2)	(49.0)	(97.0)
2026-27	-	32.3	51.4	63.5	132.8
2027-28	-	2.7	6.2	8.0	11.7
2028-29	-	(39.4)	(63.2)	(77.3)	(140.8)
2024-2029	-	(24.4)	(37.7)	(45.8)	(49.4)
Percentage Change in Costs		-0.161%	-0.248%	-0.302%	-0.325%

As indicated in Exhibit 3-14, additional storage capacity reduced overall costs in 2025/26 and 2028/29, but resulted in an increase in costs in 2024/25, 2026/27 and 2027/28. The total supply portfolio costs came down over the 5-year period when incremental storage capacity of 5PJ, 8PJ, 10PJ and 20 PJ is contracted in a typical weather case.

Exhibit 3-14 Impact of incremental storage capacity on Total Supply Portfolio Costs (Million$) in the Typical Weather cases



4 Comparison of Updated Storage Value Scenarios to October 2022 Report

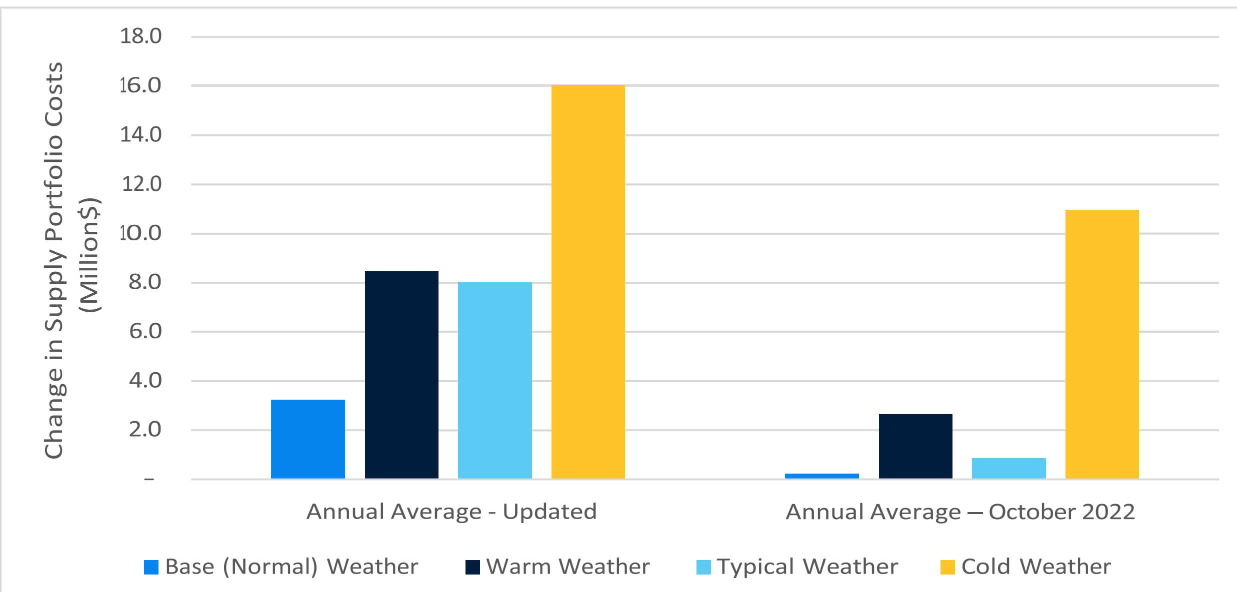
The updated analysis is compared to the analysis in the October 2022 report below:

4.1 Reduced Storage Capacity Analysis

The ICF analysis in the October 2022 Report and in this February 2024 Addendum indicate that reducing storage capacity below the level indicated by the Aggregate Excess methodology by 5 PJ would lead to higher natural gas supply portfolio costs. The results of the updated analysis were in line with the October 2022 study and indicated that reducing storage capacity below the level indicated by the Aggregate Excess methodology resulted in small reductions in the portfolio costs depending on the weather scenario selected when calculated by the supply planning model, but the reduction in portfolio costs is more than offset by the costs associated with offsetting the reduction in storage deliverability for design day planning and for system reliability and resiliency.

The Exhibit 4-1 below shows the impact of reduced storage capacity on the total supply portfolio costs on average over the 5-year period in the updated study and for the October 2022 study. In both studies there is an increase in total costs when the storage capacity is reduced by 5 PJ. The cost impact is more pronounced in the updated study.

Exhibit 4-1 Impact of Reduced Storage Capacity (5 PJ decrement) on Total Supply Portfolio Costs (Million $)



The analysis includes an adjustment for the cost of replacing the lost deliverability associated with the reduction in storage capacity. In the updated analysis, this adjustment resulted in an increase in cost savings in all of the weather scenarios. In the October 2022 analysis, this adjustment offset a modest cost impact in the normal weather case and increased the overall cost savings in the other three weather scenarios.

4.2 Resource Mix Optimization Analysis

The results of the resource mix optimization analysis indicated that when additional storage capacity was made available, different weather options resulted in distinct levels of storage capacity to optimize the cost of the Enbridge Gas supply portfolio in different years. Exhibit 4-2 shows the incremental storage capacity by year over the 5-year analysis period in the updated analysis and the October 2022 analysis. The updated analysis resulted in somewhat lower amount of storage capacity than in the October 2022 analysis in the Normal Weather and Warm Weather cases, roughly the same amount of storage capacity in the Typical Weather Case and significantly more storage capacity in the Cold Weather Case.

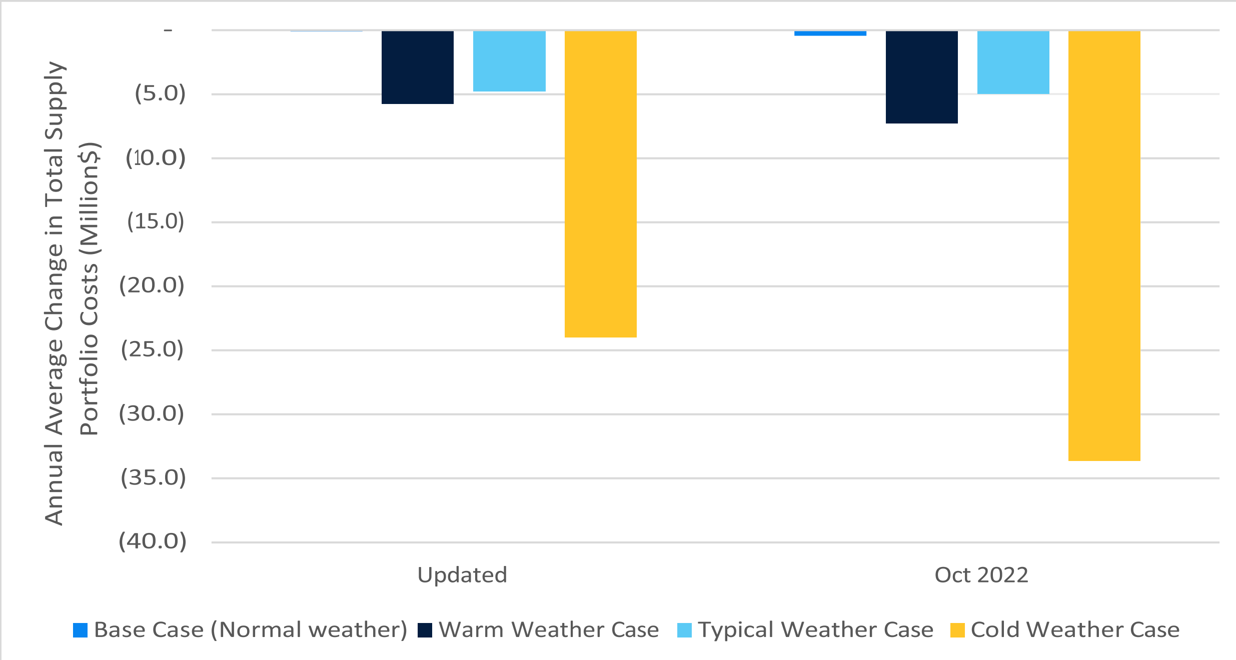
In both the updated analysis and the October 2022 analysis, more storage was picked up in the typical, warm, and cold weather cases compared to the normal weather case due to higher seasonal price volatility observed in the alternative weather cases compared to the base case.

Exhibit 4-2 Incremental Optimized Storage Capacity for Enbridge Gas In-Franchise Bundled Services Customers over the 5-year analysis period

Optimized Incremental Storage capacity						
Updated Analysis (PJs)	2024/25	2025/26	2026/27	2027/28	2028/29	Total 2024-29 (Updated)
Base Case (Normal Weather)	0.0	0.0	0.0	0.0	2.7	2.7
Warm Weather Case	0.0	0.0	9.9	30.0	0.0	39.9
Typical Weather Case	1.2	0.0	0.0	12.3	30.0	43.5
Cold Weather Case	0.0	19.2	30.0	25.3	7.9	82.4
October 2022 Analysis (PJs)	2023/24	2024/25	2025/26	2026/27	2027/28	Total 2023-28 (Oct 2022)
Base Case (Normal Weather)	0.0	0.0	0.0	0.0	10.5	10.5
Warm Weather Case	0.0	0.0	25.9	30.0	3.4	59.3
Typical Weather Case	0.0	19.1	0.0	0.0	25.3	44.3
Cold Weather Case	3.2	0.0	30.0	0.0	12.5	45.7

The overall changes in total supply portfolio costs on average for the five-year period for each of the weather scenarios with optimized storage capacity are shown in Exhibit 4-3 below.

Exhibit 4-3 Average Annual Change in Total Supply Costs due to Optimized Storage Capacity as per Enbridge Gas SENDOUT© Results (excluding adjustments for the value of incremental deliverability)



**Negative costs indicate a reduction in total supply portfolio cost

As discussed in section 3.3, in the resource mix optimization analysis, the incremental storage capacity picked across all the four weather scenarios was different. The 2024 update to the optimized storage analysis added less storage per year in the base (normal weather) case and additional storage in the Typical weather scenario.

In the Normal Weather Case, the incremental storage capacity above the currently committed levels, picked up as a part of resource optimization, would lead to a reduction in overall supply costs of C$80,200 per year in the updated analysis relative to the reduction in overall supply costs of C$438,000 per year in the October 2022.

In the Typical Weather Scenario, the incremental storage capacity above the currently committed levels would lead to a reduction in overall supply costs of C$4.79 million per year relative to the reduction in overall supply costs of C$4.97 million per year in the October 2022 analysis.

In the Warm Weather case, the incremental storage capacity would reduce the supply portfolio cost by C$5.80 million per year in the updated analysis relative to C$7.29 million per year in the October 2022 analysis. In the Cold Weather case, the incremental storage capacity would reduce the supply portfolio cost by C$24.0 million per year in the updated analysis relative to the C$33.61 million per year in the October 2022 analysis.

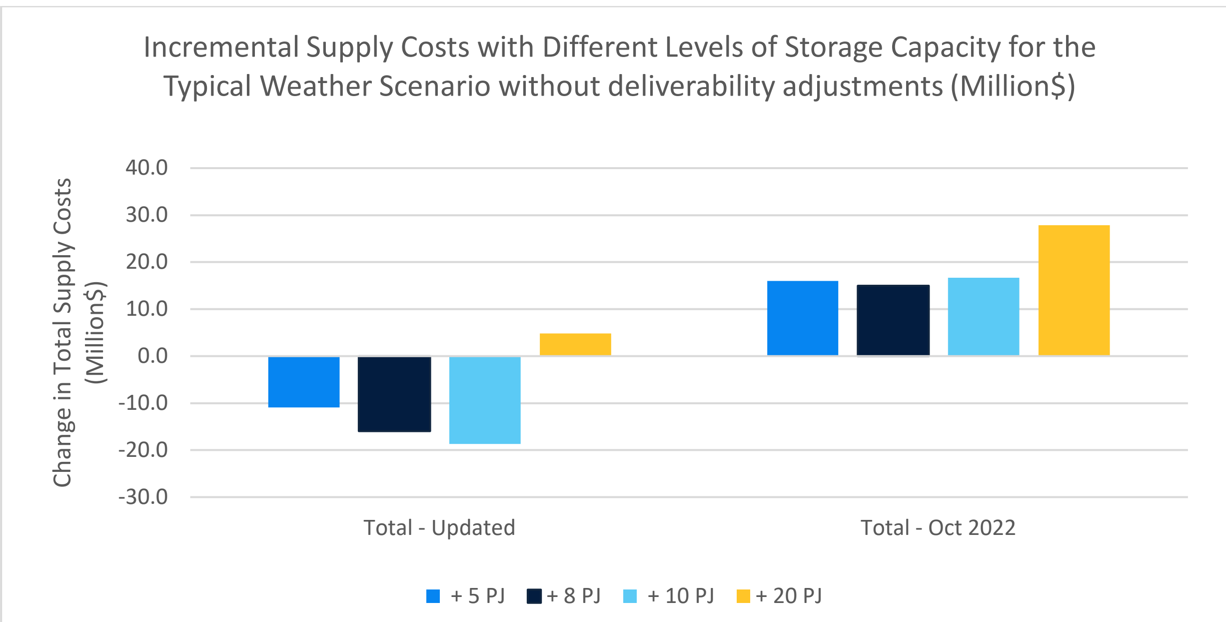
Even though the updated analysis suggested that the reduction in supply portfolio costs were slightly lower than the prior October 2022 analysis, the analysis suggested that there were cost savings when additional storage capacity was purchased.

4.3 Fixed Storage Capacity Analysis

In the October 2022 Report, ICF conducted a fixed storage capacity analysis for the Typical Weather scenario. This analysis evaluated the impacts of different levels of incremental storage capacity under typical weather conditions. This analysis was repeated for the updated report.

Exhibit 4-4 compares the impact of adding fixed storage capacity on the total supply portfolio costs for the typical weather case in the updated analysis relative to the October 2022 analysis. As shown in Exhibit 4-4, the original analysis indicated that the incremental storage capacity had a limited impact on overall supply costs, although the benefits associated with holding additional storage capacity were slightly lower than the costs of holding the incremental storage capacity, while the updated analysis indicates more substantive benefits associated with higher storage capacity. This exhibit excludes the impacts of adjustments for the value of deliverability based on the delivered service costs and the ability to minimize gas purchases during the highest price periods.

Exhibit 4-4 : Incremental Total Supply Portfolio Costs (Million$) in the Typical weather cases over the 5-year period with different storage capacity contracts excluding the cost of incremental deliverability



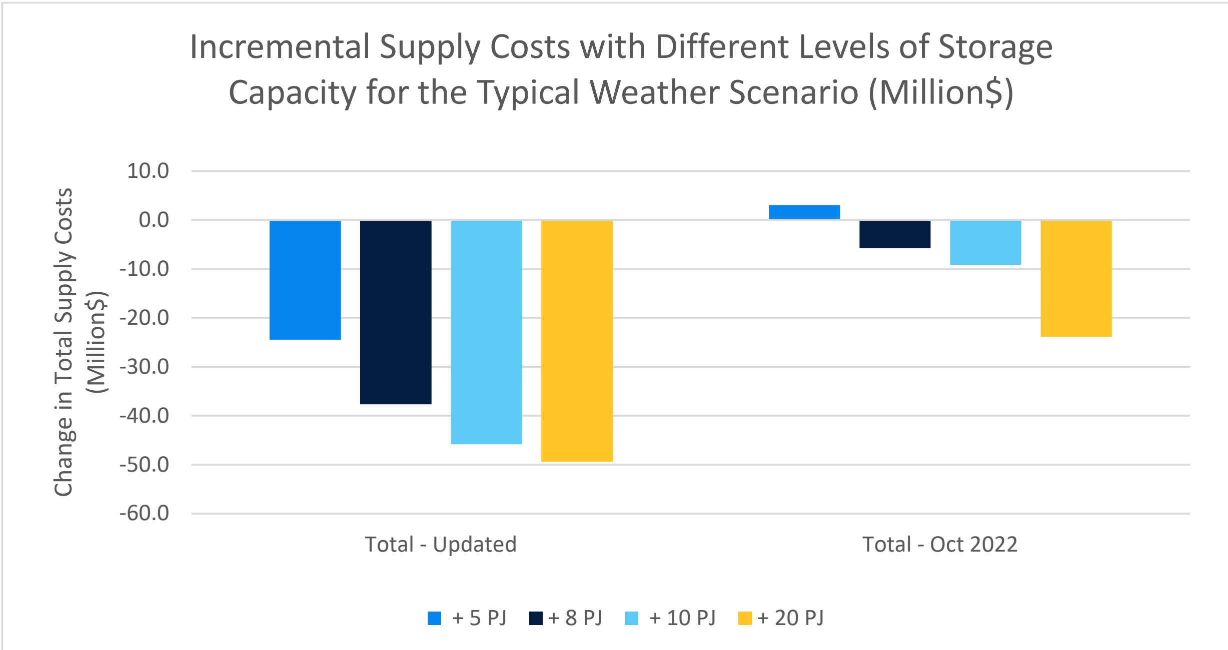
As indicated in Exhibit 4-5 below, the costs changed between -0.123% to 0.032% relative to the total supply portfolio cost depending on the amount of fixed incremental storage capacity. In the October 2022 study, the costs changed between 0.117% and 0.218% relative to the total supply portfolio cost depending on the amount of fixed incremental storage capacity when the impact of incremental deliverability was not captured.

Exhibit 4-5 : Impact of Different fixed levels of Storage Capacity on the Total Supply Costs for the Typical Weather Scenario excluding the cost of incremental deliverability – Updated vs October 2022

Incremental Total Supply Portfolio Costs with Different Levels of Storage Capacity for the Typical Weather Scenario without Adjustment for Value of Incremental Deliverability (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
Update - 2024-2029	-	(10.89)	(15.99)	(18.69)	4.80
October 2022 - 2023-2028	-	15.98	15.00	16.70	27.88
Delta	-	(26.86)	(30.99)	(35.39)	(23.08)
Update - Percentage Change in Costs		-0.072%	-0.105%	-0.123%	0.032%
Oct 2022 - Percentage Change in Costs		0.125%	0.117%	0.131%	0.218%
Delta		-0.197%	-0.230%	-0.248%	-0.093%

Exhibit 4-6 compares the impact of adding fixed storage capacity on the total supply portfolio costs for the typical weather case in the updated analysis relative to the October 2022 analysis and includes the impact of the adjustments for the value of deliverability based on the delivered services costs and the ability to minimize gas purchases during the highest price periods. As shown in Exhibit 4-6, the updated analysis indicates more substantive benefits associated with higher storage capacity when compared to the October 2022 analysis.

Exhibit 4-6 Incremental Total Supply Portfolio Costs (Million$) in the Typical weather cases over the 5-year period with different storage capacity contracts



As indicated in Exhibit 4-7 below, the costs changed between -0.325% and -0.161% relative to the total supply portfolio cost depending on the amount of fixed incremental storage capacity. In the October 2022 study, the costs changed between -0.187% and 0.024% relative to the total supply portfolio cost depending on the amount of fixed incremental storage capacity.

Exhibit 4-7 Impact of Different fixed levels of Storage Capacity on the Total Supply Costs for the Typical Weather Scenario – Updated vs October 2022 (Million$)

Incremental Total Supply Portfolio Costs with Different Levels of Storage Capacity for the Typical Weather Scenario with Adjustment for Value of Incremental Deliverability (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
Update (2024-2029)	-	(24.4)	(37.7)	(45.8)	(49.4)
October 2022 (2023-2028)	-	3.04	(5.70)	(9.18)	(23.87)
Delta	-	(27.48)	(31.97)	(36.63)	(25.55)
Update - Percentage Change in Costs		-0.161%	-0.248%	-0.302%	-0.325%
Oct 2022 - Percentage Change in Costs		0.024%	-0.045%	-0.072%	-0.187%
Delta		-0.185%	-0.203%	-0.230%	-0.139%

5 Impact of Updated Storage Analysis on Conclusions and Recommendations

Based on the analysis conducted for the October 2022 Report, ICF made the following recommendation regarding the amount of storage capacity that should be held by Enbridge Gas to support its regulated customers.

> ICF's analysis suggests that Enbridge Gas should consider increasing the amount of market-based storage capacity held for bundled service customers by about 10 PJ from 18 PJ to 28 PJ. This recommendation reflects a balance between cost, cost volatility, design day reliability, and minimizing up front contract cost commitments for supply services and reflects the results of the assessment of the value of storage under different weather conditions, and the assessment of the impacts of different levels of storage capacity on costs for the typical weather scenario.[8]

The updated analysis supports this recommendation. Overall, the supply costs for bundled in-franchise customers are expected to decline with the addition of incremental storage capacity across a range of storage capacity options when compared to the existing supply portfolio without incremental storage. In addition, the incremental storage capacity provides additional benefits related to resiliency and reliability that are not captured in this analysis.

ICF's analysis indicates that since the previous analysis was completed, the value of natural gas storage to Enbridge Gas bundled customer base has increased slightly faster than the expected cost of incremental storage capacity. Hence the value of holding incremental storage capacity has increased since the October 2022 Report was prepared.

The analysis of incremental storage value for the different weather scenarios indicated that decreasing the storage capacity below the level indicated by the aggregate excess methodology would increase overall gas supply costs, while increasing the incremental storage capacity above the level indicated by the Aggregate Excess by between 5 and 20 PJ of fixed capacity is expected to lead to additional cost savings due to the flexibility in gas purchase timing facilitated by the incremental storage capacity.

While the different approaches to evaluating the value of incremental storage capacity led to different estimates of impacts, the overall study results support the conclusion that incremental storage capacity would reduce costs and increase reliability and resiliency. It should be noted, however, that in parts of the analysis, the cost savings at the upper end of this range, when incremental storage capacity is increased from 10 PJ to 20 PJ, are smaller than the cost savings associated with the first 10 PJ of incremental capacity, and are also likely to provide fewer benefits related to reliability and resiliency. Hence the value of the higher volumes of incremental storage capacity may be limited and may not be sufficient to justify the multiple year financial commitments needed to acquire and hold this capacity.

Therefore, based on the updated analysis of the potential value of storage under different weather conditions, and the value of incremental storage capacity, ICF reaffirms the

[8] "Assessment of Storage Capacity Requirements for Enbridge Gas In-franchise Bundled Service Customers", October 12, 2022. Page 14

recommendation made in the October 2022 Report that Enbridge Gas consider increasing the amount of market-based storage by about 10 PJ above the level set by the aggregate excess methodology. This represents the best balance between the projected value of the incremental storage capacity to minimize gas supply costs, the value of reducing gas cost uncertainty and volatility, and the reliability benefits provided by storage capacity, and the fixed cost commitments needed to contract for the storage capacity.

ICF's analysis indicates that since the previous analysis was completed, the value of natural gas storage has increased faster than the expected cost of incremental storage capacity. The change in market conditions would indicate that a small increase in the recommended storage level could be appropriate. However, the incremental benefit of additional storage capacity did not change the lower bound of ICF's recommendation by enough to justify a change in the original recommendation of 10 PJ of storage capacity above the level identified by the aggregate excess methodology.

Appendix A: Incremental Value of Storage Relative to Gas Purchases at Dawn

Gas purchases at Dawn are not a perfect substitute for holding natural gas storage capacity. Storage capacity provides additional value on a daily basis relative to purchases at Dawn in several different areas. These include:

1) Contribution of Storage Deliverability to Design Day Capacity Requirements. Storage deliverability provides a direct contribution to design day system capacity requirements. In the Gas Supply Planning model analysis, changes in storage capacity are addressed through incremental purchases at Dawn. However, purchases at Dawn do not have the degree of reliability provided by storage deliverability. The difference in reliability provides significant economic benefit to the use of incremental storage that is not captured in the Gas Supply Planning model analysis.

2) Value of Daily Gas Supply Purchasing Flexibility. Storage capacity allows for a more flexible gas purchasing approach that allows the utility to shift purchases on high priced days to purchases on lower priced days. This provides a direct economic benefit to the use of storage that is not captured in the use of storage to address aggregate excess requirements, or through the use of monthly average prices.

Value of Storage Deliverability

A change in the use of market-based storage to service bundled service customers would change the reliability of natural gas supply during peak periods. In order to assess the value of this change, ICF looked at the cost of replacing lost deliverability from natural gas storage with delivered services. Based on our assessment of the market, the cost of very high deliverability market-based storage at Dawn likely would set the initial cost of delivered services. In this analysis, a change in storage capacity of one PJ would lead to a reduction in storage deliverability of 0.012 PJ. The cost of replacement deliverability is estimated to be $0.429 per GJ of storage capacity per year.[9],[10]

The storage price analysis is based on historical data on market-based storage contracts from the Enbridge Gas storage STAR Report[11] and the Enbridge Gas Storage Holders Index of

[9] Excluding the value associated with storage space

[10] Based on 1.2 percent deliverability. (1.2 * 0.3577) + (0.3577*0) = $0.429 per GJ

[11] https://www.enbridgegas.com/-/media/Extranet-Pages/Storage-and-transportation/operational-information/Storage-Reporting/STAR_storage_report_all.ashx - For the period March 1, 2023, to August 31, 2023

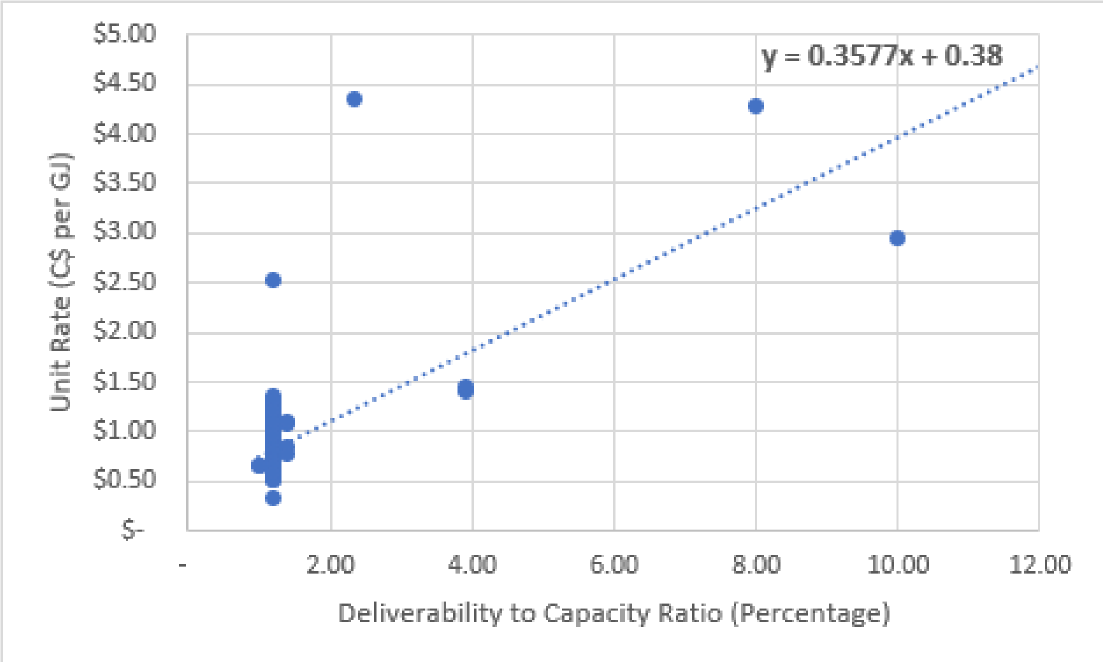
Customers[128] to create a database of market-based storage contracts with capacity, deliverability, and rates. ICF also included responses to recent Enbridge Gas RFPs for market-based storage in the storage contract value database. ICF used the integrated storage contract value database to conduct a regression analysis of the value of storage based on the space and deliverability characteristics in each contract to update the analysis in the October 2022 study. The results of the regression analysis are shown in Exhibit A-1.

Contribution from Short Term Price Volatility on Storage Value

Incremental storage capacity above the level indicated by the Aggregate Excess methodology also increases the utility's ability to optimize purchase patterns, including reducing purchases at Dawn at the highest priced days and increasing purchases at Dawn on days with lower prices. Over the last five years (2019 – 2023), the highest priced day in January has averaged about US$0.79 per MMBtu higher than the average January price. The lowest price day in January has averaged about $0.40 per MMBtu below than the average January price. Hence the ability to shift purchases from the highest cost day to the lowest cost day in January would reduce gas purchase costs by $1.19 per MMBtu. Achieving this degree of cost savings is unlikely to be feasible. However, it would be reasonable to expect a degree of cost savings associated with the flexibility in supply purchase timing associated with incremental storage capacity. ICF calculated a rough assessment of the potential savings to be C$113,165 per year per PJ of storage capacity based on the ability to shift five days per month of high-priced purchases to the average monthly price excluding the five highest price days. The monthly average prices and the 5-day high prices at Dawn are shown in Table A 1.

[12] https://www.enbridgegas.com/–/media/Extranet-Pages/Storage-and-transportation/operational-information/Index-of-customers/Storage_Report.ashx?rev=298043dc1c2241c9abf2a8a4ac8aa2d2&hash=9DA9849B78F15C206654F1E299C018B7

Exhibit A-1 Scatter Plot of Enbridge Gas Storage Contracts – Unit Rate and Deliverability to Capacity Ratio



Incremental Storage Value

Overall ICF estimated that the value of firm peak period incremental deliverability associated with storage capacity would increase the value of storage by $429,240 per PJ of storage capacity, while the ability to avoid purchases during the highest priced market periods would increase the value of storage by at least $113,165 per PJ per year. Together, these two value streams increase the value of incremental storage capacity by at least $542,405 per PJ of storage capacity per year.

Table A 1: Monthly Average prices and the 5-day high Prices at Dawn (US$/ MMBtu)

Average Monthly Price of Gas at Dawn Ex 5 Highest Price Days (US$/MMBtu)					
Year	**2019**	**2020**	**2021**	**2022**	**2023**
January	2.9	1.9	2.5	4.0	3.2
February	2.6	1.7	3.5	4.4	2.4
March	2.8	1.6	2.5	4.6	2.4
April	2.4	1.6	2.5	6.3	2.0
May	2.4	1.6	2.7	7.7	2.0
June	2.1	1.6	3.0	7.2	2.0
July	2.1	1.7	3.5	6.5	2.2
August	2.0	2.0	3.8	8.2	2.3
September	2.1	1.7	4.7	6.8	2.2
October	1.8	1.9	5.1	4.9	2.1
November	2.5	2.3	4.9	4.8	2.4
December	2.2	2.4	3.7	5.2	2.2
Average of Five Highest Price Days of Gas at Dawn (US$/MMBtu)					
Year	**2019**	**2020**	**2021**	**2022**	**2023**
January	3.8	2.1	2.7	4.8	3.7
February	3.0	1.8	6.4	5.2	2.7
March	4.3	1.7	2.7	5.2	2.8
April	2.6	1.8	2.7	7.1	2.2
May	2.5	1.9	2.8	8.5	2.3
June	2.3	1.7	3.4	8.7	2.4
July	2.3	1.8	3.8	8.4	2.4
August	2.1	2.2	4.1	8.9	2.5
September	2.4	2.1	5.2	8.3	2.4
October	2.4	2.9	5.8	5.9	2.8
November	2.8	2.8	5.4	6.8	2.7
December	2.4	2.6	4.2	6.2	2.5
Difference Between 5 Highest Price Days of Gas at Dawn and Monthly Average Ex 5 Highest Price days (US$/MMBtu)					
Year	**2019**	**2020**	**2021**	**2022**	**2023**
January	0.8	0.2	0.2	0.8	0.5
February	0.3	0.1	3.0	0.8	0.3
March	1.5	0.2	0.2	0.6	0.4
April	0.2	0.2	0.2	0.8	0.1
May	0.1	0.2	0.1	0.8	0.3
June	0.1	0.1	0.4	1.5	0.4
July	0.2	0.1	0.3	1.8	0.1
August	0.1	0.3	0.3	0.7	0.2
September	0.3	0.4	0.6	1.6	0.2
October	0.6	1.0	0.7	1.0	0.7
November	0.2	0.5	0.5	1.9	0.4
December	0.2	0.2	0.4	1.0	0.3
Annual Average	**0.4**	**0.3**	**0.6**	**1.1**	**0.3**

Appendix B: Additional Fixed storage capacity analysis

ICF extended the analysis in the Addendum and estimated the impact of incremental fixed storage capacity across the Normal, Warm and Cold Weather scenarios. This was done in addition to the typical weather scenario as discussed in 3.4 to understand if other scenarios could provide additional information.

Exhibits B-1 and B-2 below show the results for different levels of storage capacity for a normal weather scenario. As indicated in Exhibit B-2, in the normal weather scenario, additional storage capacity reduced overall costs in 2024/25, in 2027/28 and in 2028/29, but resulted in an increase in costs in 2025/26 and 2026/27 and a net increase in costs over the five year period before consideration of the potential value associated with the incremental deliverability the reduction in peak period gas purchases associated with the incremental storage capacity.

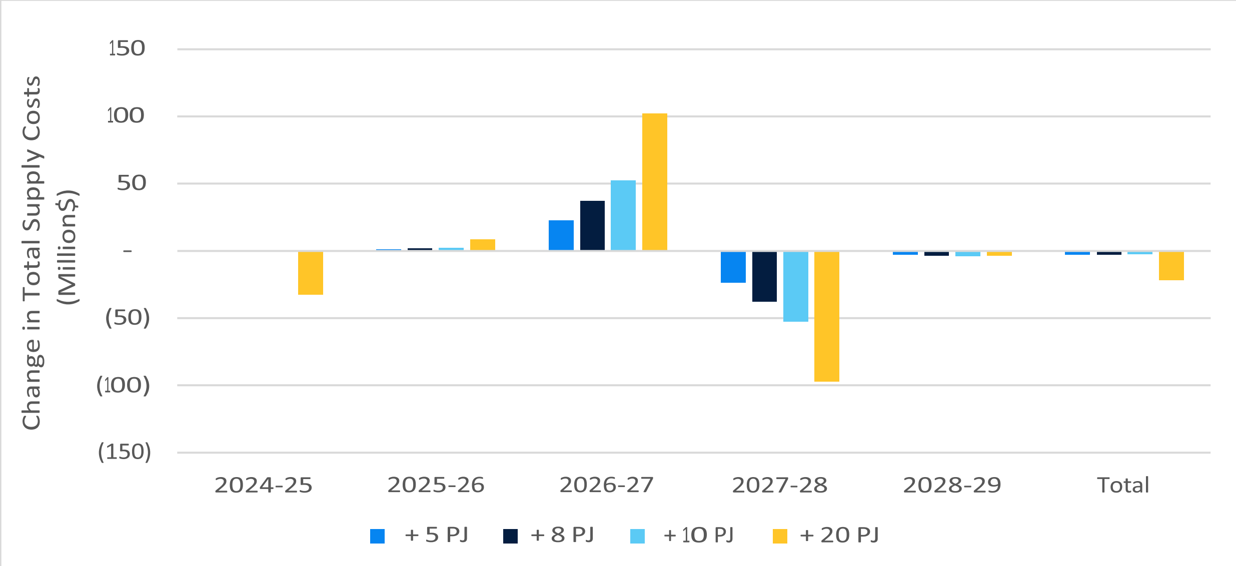
After consideration of these benefits, the results suggested cost benefits in a normal weather scenario with fixed storage capacity contracts. There are cost savings of $21.9 million in total over a 5-year period when 20 PJ of fixed capacity is contracted in a normal weather scenario.

Exhibit B-1 Impact of Different levels of Storage Capacity on the Total Supply Costs for the Normal Weather Scenario (CAD$Millions)

Total Supply Costs with Different Levels of Storage Capacity for the Normal Weather Scenario (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	2,452	2,455	2,456	2,457	2,431
2025-26	2,694	2,698	2,700	2,702	2,714
2026-27	2,724	2,749	2,765	2,782	2,837
2027-28	3,299	3,279	3,266	3,252	3,213
2028-29	3,442	3,442	3,443	3,443	3,449
2024-2029	14,611	14,622	14,630	14,636	14,644
Incremental Supply Costs with Different Levels of Storage Capacity for the Normal Weather Scenario (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	-	2.3	3.9	4.9	(21.6)
2025-26	-	3.7	6.2	7.8	19.6
2026-27	-	25.4	41.6	57.7	113.2
2027-28	-	(20.8)	(33.6)	(47.1)	(86.4)
2028-29	-	0.1	0.7	1.3	7.5
2024-2029	-	10.7	18.7	24.7	32.3
Percentage Change in Costs		**0.074%**	**0.128%**	**0.169%**	**0.221%**

	203 PJ	208 PJ	211 PJ	213 PJ	223 PJ
Value of Incremental Deliverability	-	2.1	3.4	4.3	8.6
Reduction in Gas Purchase Costs	-	0.6	0.9	1.1	2.3
Total Supply Costs with Different Levels of Storage Capacity for the Normal Weather Scenario					
With Adjustment for Value of Incremental Deliverability (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	2,452	2,452	2,452	2,452	2,420
2025-26	2,694	2,695	2,696	2,696	2,703
2026-27	2,724	2,747	2,761	2,776	2,826
2027-28	3,299	3,276	3,262	3,247	3,202
2028-29	3,442	3,439	3,438	3,438	3,438
2024-2029	14,611	14,609	14,608	14,609	14,589
Incremental Supply Costs with Different Levels of Storage Capacity for the Normal Weather Scenario (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	-	(0.4)	(0.5)	(0.5)	(32.4)
2025-26	-	1.0	1.8	2.4	8.7
2026-27	-	22.7	37.2	52.3	102.3
2027-28	-	(23.5)	(37.9)	(52.6)	(97.2)
2028-29	-	(2.7)	(3.6)	(4.1)	(3.4)
2024-2029	-	(2.8)	(3.0)	(2.5)	(21.9)
Percentage Change in Costs		**-0.019%**	**-0.020%**	**-0.017%**	**-0.150%**

Exhibit B-2 Impact of Incremental Storage Capacity on Total Supply Portfolio Costs (Million$) Normal Weather Case



The exhibit B-3 below show the results for different levels of storage capacity for a Warm weather scenario. As indicated in exhibit B-4, in the warm weather scenario, additional storage capacity reduced overall costs in 2025/26 and in 2027/28, but resulted in an increase in costs in 2024/25, 2026/27, and 2028/29. Over the 5-year period, costs increase at all levels of incremental storage capacity prior to consideration of the value of incremental deliverability and the ability to minimize peak period gas purchases. After consideration of the value of incremental deliverability, the 5 PJ, 8 PJ and 10PJ cases result in lower overall supply costs, while the 20 PJ case results in higher overall supply costs. Costs changed by between -0.048% and 0.328% relative to the total supply portfolio cost depending on the amount of incremental storage capacity.

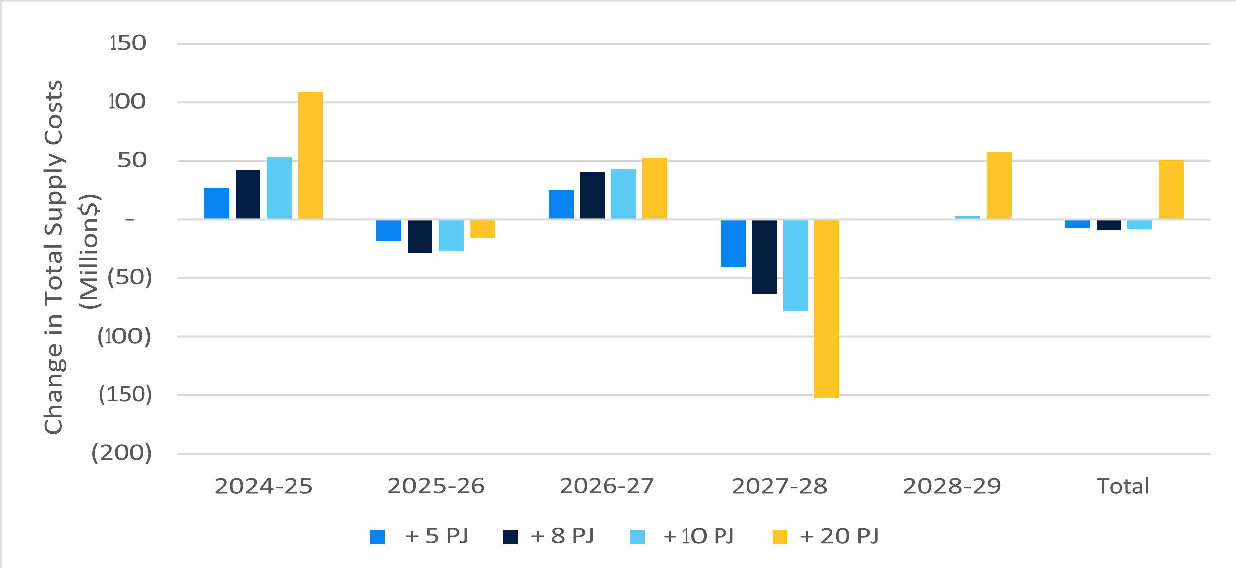
Exhibit B-3 Impact of Different levels of Storage Capacity on the Total Supply Costs for the Warm Weather Scenario (CAD $Millions)

Total Supply Costs with Different Levels of Storage Capacity for the Warm Weather Scenario (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	2,374	2,403	2,421	2,432	2,493
2025-26	2,619	2,604	2,595	2,597	2,614
2026-27	2,618	2,645	2,662	2,666	2,681
2027-28	4,192	4,155	4,133	4,119	4,051
2028-29	3,544	3,546	3,548	3,551	3,612
2024-2029	15,346	15,352	15,359	15,366	15,451
Incremental Supply Costs with Different Levels of Storage Capacity for the Warm Weather Scenario (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	-	29.1	46.7	58.4	119.4

2025-26	-	(15.3)	(24.4)	(21.8)	(5.0)
2026-27	-	27.8	44.7	48.2	63.5
2027-28	-	(37.5)	(59.1)	(73.0)	(141.7)
2028-29	-	2.1	4.8	7.7	68.3
2024-2029	-	6.2	12.6	19.5	104.6
Percentage Change in Costs		**0.040%**	**0.082%**	**0.127%**	**0.681%**

	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
Value of Incremental Deliverability	-	2.1	3.4	4.3	8.6
Reduction in Gas Purchase Costs	-	0.6	0.9	1.1	2.3
Total Supply Costs with Different Levels of Storage Capacity for the Warm Weather Scenario					
With Adjustment for Value of Incremental Deliverability (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	2,374	2,400	2,416	2,427	2,482
2025-26	2,619	2,601	2,590	2,592	2,603
2026-27	2,618	2,643	2,658	2,660	2,670
2027-28	4,192	4,152	4,129	4,114	4,040
2028-29	3,544	3,543	3,544	3,546	3,601
2024-2029	15,346	15,339	15,337	15,339	15,397
Incremental Supply Costs with Different Levels of Storage Capacity for the Warm Weather Scenario (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	-	26.4	42.4	53.0	108.6
2025-26	-	(18.1)	(28.7)	(27.3)	(15.9)
2026-27	-	25.1	40.3	42.8	52.7
2027-28	-	(40.2)	(63.5)	(78.4)	(152.5)
2028-29	-	(0.6)	0.4	2.3	57.4
2024-2029	-	(7.4)	(9.1)	(7.6)	50.3
Percentage Change in Costs		**-0.048%**	**-0.059%**	**-0.050%**	**0.328%**

Exhibit B-4 Impact of Incremental Storage Capacity on Supply Costs (Million$) - Warm Weather Case



The exhibit B-5 below show the results for different levels of storage capacity for a Cold weather scenario. As indicated in exhibit B-6, in the cold weather scenario, additional storage capacity reduced overall costs in four out of the five years and the total cost savings are much higher in a cold weather scenario both before and after consideration of the value of incremental deliverability peak period gas purchase cost savings. Costs changed by between -0.455% and -1.315% relative to the total supply portfolio cost depending on the amount of incremental storage capacity.

Exhibit B-5 Impact of Different levels of Storage Capacity on the Total Supply Costs for the Cold Weather Scenario (CAD$Millions)

Total Supply Costs with Different Levels of Storage Capacity for the Cold Weather Scenario (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	2,646	2,653	2,658	2,661	2,677
2025-26	2,816	2,793	2,778	2,769	2,721
2026-27	3,212	3,195	3,185	3,179	3,157
2027-28	3,432	3,415	3,406	3,404	3,395
2028-29	3,222	3,217	3,215	3,216	3,232
2024-2029	15,329	15,273	15,243	15,228	15,182
Incremental Supply Costs with Different Levels of Storage Capacity for the Cold Weather Scenario (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	-	7.3	11.9	15.0	31.1
2025-26	-	(23.7)	(38.1)	(47.7)	(95.1)
2026-27	-	(17.2)	(27.4)	(33.3)	(55.1)
2027-28	-	(17.8)	(25.8)	(28.5)	(37.5)
2028-29	-	(4.9)	(6.8)	(6.3)	9.2

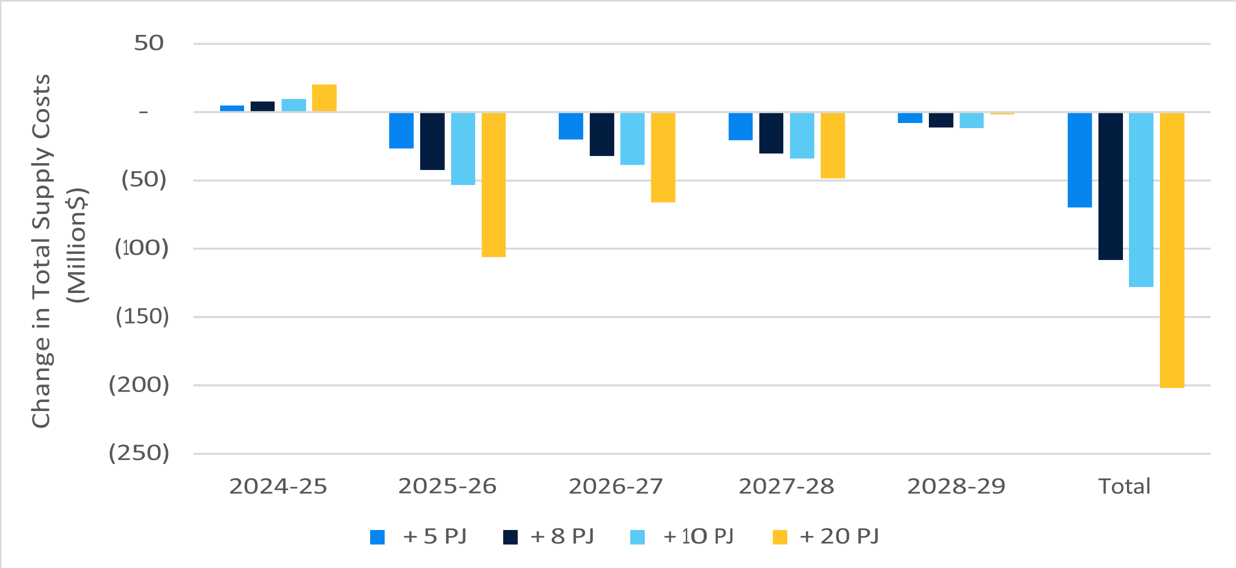
2024-2029	-	(56.2)	(86.2)	(100.8)	(147.4)
Percentage Change in Costs		**-0.367%**	**-0.562%**	**-0.658%**	**-0.961%**

	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
Value of Incremental Deliverability	-	2.1	3.4	4.3	8.6
Reduction in Gas Purchase Costs	-	0.6	0.9	1.1	2.3

Total Supply Costs with Different Levels of Storage Capacity for the Cold Weather Scenario With Adjustment for Value of Incremental Deliverability (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	2,646	2,650	2,653	2,655	2,666
2025-26	2,816	2,790	2,774	2,763	2,711
2026-27	3,212	3,192	3,181	3,174	3,146
2027-28	3,432	3,412	3,402	3,398	3,384
2028-29	3,222	3,215	3,211	3,211	3,221
2024-2029	15,329	15,259	15,221	15,201	15,127

Incremental Supply Costs with Different Levels of Storage Capacity for the Cold Weather Scenario (Million$)					
	203 PJ	**208 PJ**	**211 PJ**	**213 PJ**	**223 PJ**
2024-25	-	4.6	7.6	9.6	20.3
2025-26	-	(26.4)	(42.4)	(53.1)	(105.9)
2026-27	-	(19.9)	(31.8)	(38.7)	(66.0)
2027-28	-	(20.5)	(30.2)	(34.0)	(48.3)
2028-29	-	(7.6)	(11.1)	(11.7)	(1.6)
2024-2029	-	(69.8)	(107.9)	(127.9)	(201.6)
Percentage Change in Costs		**-0.455%**	**-0.704%**	**-0.835%**	**-1.315%**

Exhibit B-6 Impact of Incremental Storage Capacity on Total Supply Portfolio Costs (Million$) Cold Weather Case



Assessment of Storage Capacity Requirements for Enbridge Gas In-franchise Bundled Service Customers

October 12 , 2022

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Contents

1 Introduction and Summary

1.1 Purpose

As part of the 2024 Rebasing Application (referred to as the Application), designed to set rates as of January 1, 2024, Enbridge Gas Inc. (referred to as Enbridge Gas) is proposing to integrate the storage planning process as a result of the amalgamation of Enbridge Gas Distribution (EGD) and Union Gas Limited (Union) on January 1, 2019.

Enbridge Gas also agreed to provide more information on storage costs and market-based alternatives to the purchase of third-party storage in its supply portfolio as part of this application:

> "In connection with the settlement of this item, Enbridge Gas has agreed to file evidence in its rebasing application (for rates as of January 1, 2024, which will include requests for approvals for the pass-through of gas supply costs) demonstrating that it has fully considered the opportunity to reduce storage costs through inclusion, as part of its load balancing portfolio, of cost-effective market-based alternatives to the purchase of third-party storage. That evidence will include consideration of: (i) the cost of delivered supply (including the commodity cost) in winter in lieu of contracting for additional storage: versus (ii) the cost (savings) of buying gas in summer and the associated additional storage and related costs required to store and redeliver that gas in the winter."[1]

Enbridge Gas retained ICF to assess the appropriate mix of winter supply purchases as compared to holding storage assets for meeting Enbridge Gas's load balancing needs for bundled service customers. As part of this engagement, Enbridge Gas informed ICF that the Application reflects 218 PJ of storage services to serve in-franchise customers. This includes 203[2] PJ of storage services to serve the utility's bundled in-franchise customer gas supply requirements and 15 PJ of capacity for T-Service customers. Enbridge requested that ICF evaluate the proposed level of storage services and make recommendations on whether Enbridge should change the level of storage capacity.

This report documents ICF's recommendations on the level of contracted storage capacity that would be optimal for Enbridge Gas and provide an assessment of the determination of Enbridge Gas' natural gas storage requirements relative to other market-based alternatives for bundled service customers.

1.2 Structure of Report

This report documents the results of ICF's market analysis and storage value analysis and provides an assessment of the current Enbridge Gas methodology of determining storage requirements and whether there is benefit to modifying this approach. The remainder of **Section 1** provides an overview of the analysis and a summary of results. **Section 2** of this report provides an overview of the key market trends expected to determine storage value and utilization in the future. **Section 3** of this report provides a broad overview of the alternatives to market-based storage capacity. **Section 4** documents the approach used in the storage analysis and provides results of ICF's analysis and recommendations for Enbridge Gas future storage capacity. ICF's conclusions and recommendations are presented in **Section 5** of the report.

[1] Footnote o/s

[2] The 203 PJ of storage capacity for bundled service customers includes 185 PJ of utility owned storage near the Dawn Hub provided at the cost of service, and 18 PJ of physical and synthetic storage services contracted from third parties at market-based rates near the Dawn Hub

1.3 Overview of Approach

The ICF assessment of the value of storage capacity for Enbridge Gas in-franchise customers is based on a combination of different analytical methodologies for assessing natural gas markets.

- ICF used the Enbridge Gas forecast of natural gas demand for the 2023-2028 time-period throughout the analysis.[3]
- ICF used its April 2022 Gas Market Model (GMM) as the starting basis for its evaluation of the North American natural gas markets and Enbridge Gas' gas storage operations. The GMM is an internationally recognized model of the North American gas market that includes projections for natural gas demand by sector, conventional and unconventional natural gas resources, production costs, and other major gas market developments, such as potential Liquefied Natural Gas (LNG) exports. The GMM projects monthly natural gas demand, supply, and prices for more than 120 regions and is a general equilibrium market model. The model is described in more detail in Appendix C. ICF used the GMM to conduct analysis of the potential impacts and risks associated with alternative weather scenarios on natural gas demand and prices.
- ICF developed a series of alternative weather scenarios to assess the impact of different weather patterns on storage value. These weather scenarios were based on real weather patterns over a five-year period.
- ICF requested that Enbridge Gas perform a set of portfolio analysis optimization scenarios to assess the value of storage capacity under different gas price and weather scenarios. Enbridge Gas used their gas supply planning model (Supply Planning Model)[4] to conduct this analysis. The analysis uses a base gas supply portfolio which represents the bundled demand and assets that EGI determined to be consistent with the use of Aggregate Excess to determine storage capacity. The Enbridge Gas analysis is underpinned by EGI's demand forecast, and Enbridge Gas' upstream contract costs at the time of developing the Application.

  We also tested each weather scenario using a lower storage capacity gas supply scenario developed with 5 PJ less storage than indicated by the Aggregate Excess methodology to evaluate the impacts of replacing storage capacity with winter purchases at Dawn on supply portfolio costs.

  We then tested each weather scenario to determine the impact of increasing storage capacity and reducing the reliance on winter purchases at Dawn using two different approaches to test different levels of storage capacity. EGI modeled three 10 PJ tranches of incremental market-based storage and included them in the Aggregate Excess portfolio. EGI assumed each 10 PJ tranche was 5% more expensive than EGI's most recent market-based storage contract and assumed the contracting parameters similar to existing physical storage services contracted by Enbridge Gas in recent years, with 1.2% maximum deliverability and 0.75% maximum injectability.

  Once the incremental storage tranches were included in the Aggregate Excess portfolio, EGI ran Supply Planning Model using the Application's Resource Mix optimization function for each commodity price forecast provided by ICF. With SENDOUT© optimizing using the Resource Mix function and assuming each of the ICF commodity price forecasts, the gas supply planning model was able to determine what

[3] ICF did not assess the impact of changes in Enbridge Gas in-franchise customer demand on the value of storage. Increases or decreases in demand due to local weather or due to changes in customer demand trends would lead to changes in the value of storage.
[4] The Enbridge Gas Supply Planning Model is based on the SENDOUT© gas dispatch optimization framework.

level of incremental storage, if any, provided a lower cost portfolio than the Aggregate Excess portfolio.

We then asked Enbridge to fix the level of incremental storage capacity at different levels for one weather scenario to confirm the results of the optimization analysis.

- ICF used the results of the analysis to assess the value of increasing or decreasing natural gas storage capacity relative to the levels currently held by Enbridge Gas for bundled in-franchise customers.

Assessment of Enbridge Gas Aggregate Excess Methodology

Historically, Enbridge Gas has used an aggregate excess approach to determining storage requirements, with minor differences[5] between the methodology used by EGD and Union service territories. According to the OEB, “The aggregate excess method is the difference between the amount of gas a customer is expected to use in the 151-day winter period and the amount that would be consumed in that period based on the customer’s average daily consumption over the entire year.”[6] The aggregate excess methodology provides an estimate of the amount of storage capacity needed to optimize the utilization of contracted pipeline assets and minimize the uncertainty associated with meeting natural gas demand under normal weather conditions.

In and of itself, the aggregate excess methodology does not determine the optimal amount of storage capacity needed to minimize long term supply costs.

- In a market with significant excess pipeline capacity or other sources of winter gas supply being available at costs that are lower than the cost of meeting winter demand with storage, the aggregate excess methodology could result in a higher cost supply portfolio than holding a lesser amount of storage.
- However, in a market where prices and demand are more volatile than the normal conditions used to assess the amount of aggregate excess, and where there is limited available winter pipeline capacity or supply, or the available supply is higher cost than storage, the aggregate excess methodology will underestimate the amount of storage that should be held in an optimal supply portfolio.

In addition, the Aggregate Excess methodology is designed around normal weather. During some years, total supply costs might be lower if storage levels below the level indicated by aggregate excess are included in the portfolio, and in other years, the supply costs might be lower if storage levels above the aggregate excess are included in the portfolio.

The calculation of Aggregate Excess is based on a demand forecast reflecting normal weather. Standard variation in weather will lead to different valuations of the aggregate excess storage capacity. During some years, total supply costs might be lower if storage levels below the aggregate excess are included in the portfolio, and in other years, the supply costs might be lower if storage levels above the aggregate excess are included in the portfolio.

The expected seasonal swings in prices, combined with the limited availability of incremental pipeline capacity

[5] The Aggregate Excess methodologies used by legacy EGD and legacy Union Gas differed slightly based on the inclusion of own-use demand in the legacy Union Gas methodology and exclusion of own-use demand in the legacy EGD methodology. As the starting point for the Rebasing Application, Enbridge Gas used the legacy EGD methodology, which results in a lower level of indicated natural gas storage. The legacy Union Gas approach would have indicated an Aggregate Excess level of 208 PJ of storage capacity rather than 203 PJ.

[6] Ontario Energy Board, “Motions to Review the Natural Gas Electricity Interface Review Decision – Decision with Reasons” May 22, 2007. Page 59.

and the availability of storage capacity in the market region support the contracting for incremental market-based storage capacity up to the level indicated by the aggregate excess methodology. For the purpose of evaluating the optimal level of storage and to provide an assessment of market-based alternatives, ICF asked Enbridge Gas to provide a gas supply planning model run for the base case where additional market-based storage capacity was available as part of the solution. Under normal weather conditions, the Enbridge Gas's Supply Planning Model selected incremental storage capacity in the solution in one out of the five years evaluated. The reduction in supply costs during this one year more than offset the increase in cost of holding the incremental market-based storage capacity for the full five-year period, supporting the hypothesis that the Aggregate Excess methodology generally understates the optimal amount of storage capacity that should be included in the long-term Enbridge Gas supply portfolio.

Development of Alternative Weather Scenarios

The Aggregate Excess methodology does not address the value of natural gas storage with respect to system reliability and resiliency, or to protect against unpredictable supply pricing events resulting from volatile weather and pricing conditions that occur during real world weather and pricing conditions. This is consistent with most natural gas supply planning approaches. Most natural gas supply planning is based on "normal" weather conditions, with accommodations to account for design day or peak day demands that typically would occur due to extremes in weather conditions and with accommodations for colder than normal winters.

However, in the near term, changes in North American weather patterns are an important driver of storage value. The impact on value is seen both in the role that natural gas storage plays in optimizing natural gas supply portfolio costs, as well as in the market price for storage.

The ICF Base Case forecast of natural gas prices is based on a "normal" weather pattern based on 20-year average HDD patterns. The use of normal weather allows for a consistent forecast based on the same season weather pattern every year. As a result, the normal weather forecast identified the impact of other expected changes in natural gas markets, including the impact of supply and demand trends, but does not capture the impact of changes in weather. In addition, the use of a normal weather forecast leads to a dampening of the typical year-to-year differences in natural gas markets and market prices caused by the difference between actual weather patterns which vary widely from year to year, and "normal" weather. Actual weather conditions fluctuate more on a monthly basis than normal weather, which has the same seasonal pattern every year and which is created as an average of many years of actual data. As a result, use of normal weather tends to underestimate the value of natural gas storage in a utility supply plan.

The use of normal weather in the planning process ignores the impact of year-to-year market price and demand volatility in gas markets. In addition, since the normal weather assumptions are based on a 20-year average data, normal weather does not capture any extreme weather events which tend to increase or decrease demand and in turn cause rapid price swings. Much of the value of natural gas storage capacity is captured during a limited number of years when weather is colder than normal or when natural gas market conditions result in significant price increases and constraints on natural gas market availability.

To assess the value of natural gas storage for Enbridge Gas under different weather scenarios, ICF used the GMM to develop four alternative price scenarios reflecting different weather patterns (Normal weather, Warmer than Normal Weather, Typical Weather and Colder than Normal Weather).[7] The first scenario is based on

[7] The ICF Weather Scenarios used actual North American weather data to project natural gas prices at different market centers under different weather patterns. We used the base case Enbridge Gas demand forecast throughout the rest of analysis.

normal weather reflecting average weather patterns over a 20-year period from 2002 to 2021. This is consistent with the Enbridge Gas weather normal assumptions. The other three scenarios were based on actual five years of weather data rather than an average of weather over multiple years:

1) The Warmer than Normal Weather scenario is based on the actual monthly HDD data for the warmest 5-year period between 1980 and 2020. This was 2015 - 2019.

2) The Typical Weather scenario is based on actual monthly HDD data for the 5-year period that most closely matched the HDD data in the Normal Weather scenario. This was 2008 – 2012.

3) The Colder than Normal Weather scenario is based on the actual monthly HDD data for the coldest 5-year period between 1980 and 2020. This was 1981 - 1985.

The use of actual weather scenarios is an important consideration to allow for a more complete assessment of the actual range of impacts due to the range of positive and negative correlations between the weather patterns of different regions across North America.

The four different weather scenarios lead to significant changes in natural gas commodity prices, including both the absolute prices and the month to month and year to year price volatility. All three of the alternative weather scenarios that are based on actual weather patterns exhibited greater price volatility than the normal weather case, leading to additional value for natural gas storage. The resulting commodity prices across the four weather cases (shown in Exhibit 4-3) were used by Enbridge Gas to assess the impact of alternative storage scenarios on Enbridge Gas' natural gas supply portfolio costs using the Enbridge Gas Supply Planning model.

1.4 Analysis of Storage Value

The evaluation of the value of natural gas storage in the Enbridge Gas' bundled customer supply portfolio started from the storage capacity requirements proposed by Enbridge Gas in the rebasing application, consistent with the level of storage indicated by the Aggregate Excess methodology. Based on the Enbridge forecast of demand, Enbridge Gas would need to continue to maintain the current 203 PJ of cost of service and market-based storage capacity, increasing to 208 PJ of storage capacity by 2027/28 to provide the service underpinning the Aggregate Excess methodology.

In order to evaluate the potential costs and benefits of diverging away from the Aggregate Excess methodology, ICF performed three sets of analysis:

1) **Reduced Storage Capacity Analysis** –ICF evaluated a supply plan based on a minimum storage capacity 5 PJ lower than the level suggested by the Aggregate Excess methodology. The purpose of this analysis is to evaluate the impact on total portfolio costs of holding less storage than the amount identified using the Aggregate Excess methodology. The results of this analysis suggest that incremental storage capacity should also be considered.

2) **Resource Mix Optimization Analysis** – ICF used the results of the Enbridge Gas's gas supply planning model analysis to evaluate the impact of changes in storage capacity for the Base (or Normal Weather) case and for each of the three alternative weather scenarios to determine the potential costs and benefits of changing the amount of storage capacity used by Enbridge Gas relative to the currently contracted level of storage capacity. The purpose of this analysis is to determine the range of incremental storage the Enbridge Gas Supply Planning model would select under different weather scenario price forecasts, in order for ICF to determine a fixed level of storage to evaluate.

3) **Fixed Storage Capacity Analysis** – In the Resource Mix Optimization Analysis, the Enbridge Supply Model selected the optimum storage capacity in each year and operated the storage system according to the amount of storage selected. This analysis suggested that incremental storage capacity would provide value to Enbridge in-franchise bundled service customers. In order to validate the results of this analysis, ICF also requested that Enbridge Gas run their Supply Planning Model analysis with fixed amounts of incremental storage capacity over the 5-year planning period. The 5 PJ, 8 PJ, 10 PJ and 20 PJ amounts evaluated in this analysis were selected by ICF to approximate the range of incremental capacity identified in the Resource Mix Optimization analysis.

   ICF based the Fixed Storage Capacity Analysis on the typical weather scenario rather than the Normal Weather scenario since the typical weather case is a better representation of how weather conditions impact price and weather volatility. Given the results of the Resource Mix Optimization analysis, it was clear that additional storage would provide additional benefits in the warm and cold weather scenarios, hence the additional analysis would not have provided sufficient value to justify the level of effort required.

The results of the three sets of analysis are summarized below.

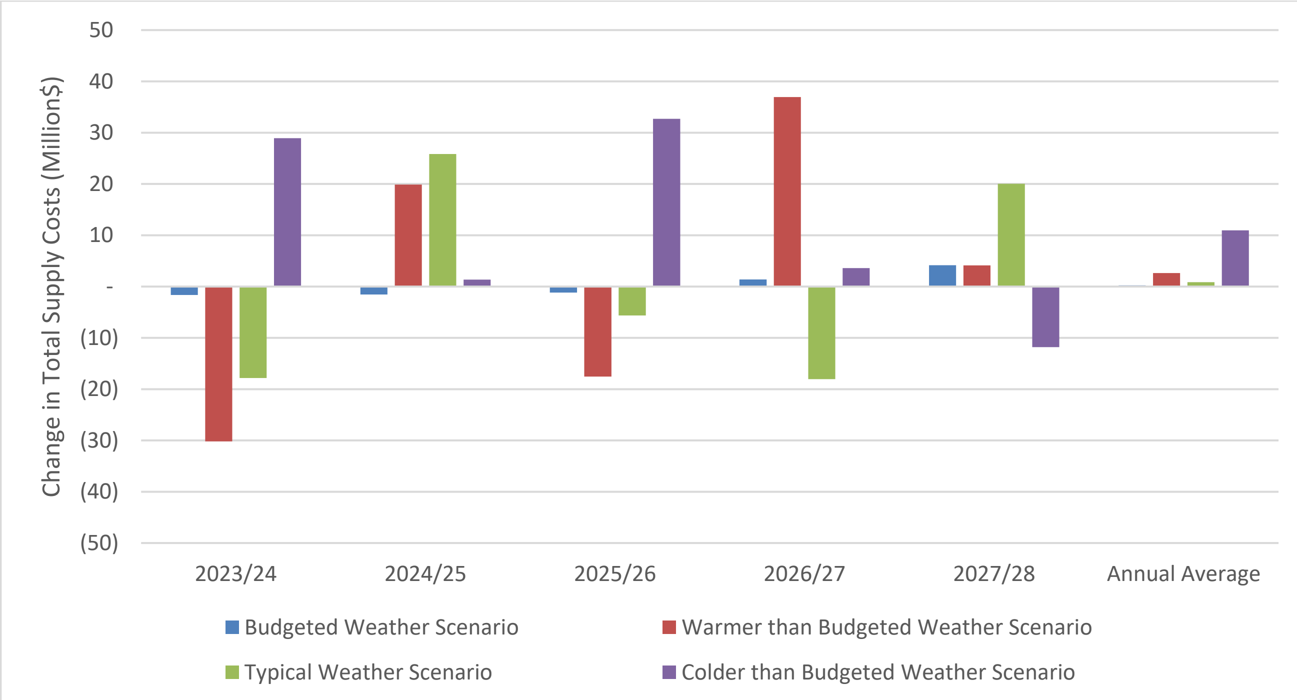
<u>Reduced Storage Capacity Analysis</u>

As outlined in Section 3, Enbridge Gas asked ICF to address whether there were viable market-based alternatives to the market-based storage capacity, and whether these alternatives would allow Enbridge Gas to hold less market-based storage capacity to serve bundled service customers. ICF considered two broad alternatives to the use of market-based storage capacity in the bundled service customer supply portfolio; 1) the potential to hold additional pipeline capacity to serve the load served by the market-based storage; and 2) the substitution of incremental purchases at Dawn for winter storage withdrawals, combined with winter peaking service to offset the storage contributions to design day.

As explained in Section 3, incremental pipeline capacity is not likely to be available or would require additional capacity on upstream pipelines to provide reliable winter service to Dawn and would not be a cost-effective alternative. However, incremental purchases at Dawn would be a potentially viable alternative to holding storage capacity.

In order to assess the impact on the supply portfolio of reducing storage capacity, Enbridge Gas ran the Supply Model with a 5 PJ decrement relative to the amount of storage capacity indicated by the Aggregate Excess methodology for each of the four weather scenarios. The results of the analysis indicate that reducing storage capacity below the level indicated by the Aggregate Excess methodology can result in small reductions in the portfolio costs depending on the weather scenario selected when calculated by the supply planning model, but the reduction in portfolio costs would be more than offset by the costs associated with offsetting the reduction in storage deliverability for design day planning and for system reliability and resiliency. Exhibit 1-1 is a summary of the change in total portfolio costs when reducing the storage portfolio by 5 PJ:

Exhibit 1-1 : Summary of Impact of Reduced Storage Capacity on Portfolio Cost



Resource Mix Optimization Analysis

The results of the analysis of the reduction in storage capacity suggested that an increase in storage capacity above the level indicated by the Aggregate Excess methodology should also be considered. In order to assess the potential value of incremental storage capacity, ICF requested that Enbridge Gas run the Gas Supply model allowing the model to select the optimum amount of storage capacity for each of the weather scenarios considered.

The results of the resource mix optimization analysis indicated when additional storage capacity was made available the analysis of the different weather options resulted in different levels of storage capacity to optimize the cost of the Enbridge Gas supply portfolio in different years. As shown in Exhibit 1-2, in some years no additional storage capacity was utilized in the optimized supply dispatch, while in other years, up to 30 PJ of additional market-based storage capacity was utilized to optimize the supply portfolio.[8] More storage was picked up in the warm and cold weather cases compared to the normal weather case due to higher seasonal demand seen across these cases.

[8] The analysis did not consider the addition of more than 30 PJ of incremental storage capacity.

Exhibit 1-2 : Optimized Storage Capacity for Enbridge Gas In-Franchise Bundled Services Customers

Optimized Storage Capacity (PJ)					
	2023/24	2024/25	2025/26	2026/27	2027/28
Aggregate Excess Storage Capacity					
Normal Weather Case	203	203	203	203	203
Warm Weather Case	203	203	203	203	203
Typical Weather Case	203	203	203	203	203
Cold Weather Case	203	203	203	203	203
Incremental Storage Capacity					
Normal Weather Case	0.0	0.0	0.0	0.0	10.5
Warm Weather Case	0.0	0.0	25.9	30.0	3.4
Typical Weather Case	0.0	19.1	0.0	0.0	25.3
Cold Weather Case	3.2	0.0	30.0	0.0	12.5
Total Optimized Storage Capacity					
Normal Weather Case	203	203	203	203	213
Warm Weather Case	203	203	229	233	206
Typical Weather Case	203	223	203	203	229
Cold Weather Case	206	203	233	203	215

As illustrated in Exhibit 1-2, the Normal weather case required additional storage capacity in one year out of the five-year period evaluated, the Typical Weather Case was optimized with additional storage in two out of five years, and the warm weather and cold weather cases were optimized with additional storage capacity in three out of the five years.

These results would imply that the optimal amount of storage capacity held in the Enbridge Gas supply portfolio should vary from year to year between 203 PJ and 233 PJ based on weather and market conditions. However, the storage market does not operate in a world with perfect foresight into weather and gas market conditions. In addition, market-based storage capacity cannot efficiently be contracted and de-contracted on a year-by-year basis.[9]

Instead, the amount of storage capacity included in the utility's annual supply portfolio must be determined without knowing future weather conditions, and with limited insight into changes in natural gas market conditions. In a supply portfolio optimized without perfect foresight, we would anticipate that the amount of storage capacity included in the supply portfolio would be relatively stable from year to year, responding to changes in natural gas demand forecasts and changes in natural gas market conditions, but not changing based on year-to-year changes in weather.

This approach will lead to years where the utility could have reduced supply costs by holding additional storage capacity, and other years where the utility could have reduced supply costs by holding less storage capacity. To assess the optimal amount of storage for the Enbridge Gas supply portfolio, ICF evaluated the balance between the cost savings associated with holding additional storage capacity in the years where the additional storage

[9] A certain amount of incremental storage capacity likely would be available on an annual basis. However, the cost of the incremental storage would fluctuate with the market, and likely would be highest during periods when prices are increasing, and when the storage would provide the most potential value to the utility.

capacity provided incremental value to the costs of holding additional storage capacity in the years where the additional storage capacity was not needed.

The overall change in total gas costs for the five-year period from April 2023 through March 2028 for each of the weather scenarios are shown in Exhibit 1-3[10].

Exhibit 1-3 : Average Annual Change in Total Gas Costs from Incremental Storage Capacity from Enbridge Gas SENDOUT© Results

Average Annual Impact of Incremental Storage Capacity on Enbridge Gas Supply Portfolio Costs for the Five-Year Period from April 2023 to March 2028 *(CAD$Millions)*	
Normal Weather Scenario	(0.4)
Warm Weather Scenario	(7.3)
Typical Weather Scenario	(4.9)
Cold Weather Scenario	(33.6)

**Negative costs imply a reduction in total cost

ICF's analysis indicates that over the five-year period evaluated, the value of holding incremental storage capacity in the years when it was useful more than offset the cost of holding the same storage capacity in the years where the storage capacity was not useful. In the Normal Weather Case, adding an additional 11 PJ of storage capacity above the currently committed levels would lead to a reduction in overall supply costs of C$438,000 per year. In the Typical Weather Scenario, adding an additional 25 PJ of storage capacity above the currently committed levels would lead to a reduction in overall supply costs of C$4.97 million per year.

In both the Warm Weather Case and the Cold Weather case, the analysis indicated that adding 30 PJ of storage capacity would be economic over the five-year period. In the Warm Weather case, the incremental storage capacity would reduce the supply portfolio cost by C$7.3 million per year, while in the Cold Weather case, the incremental storage capacity would reduce the supply portfolio cost by C$33.6 million per year.

As a result of the outcome and incremental storage amounts identified in Exhibit 1-2, ICF used this to determine a range of incremental storage levels to evaluate, holding these amounts constant over the 5-year period, which more closely replicates how a utility would contract for storage capacity.

<u>Fixed Storage Capacity Analysis</u>

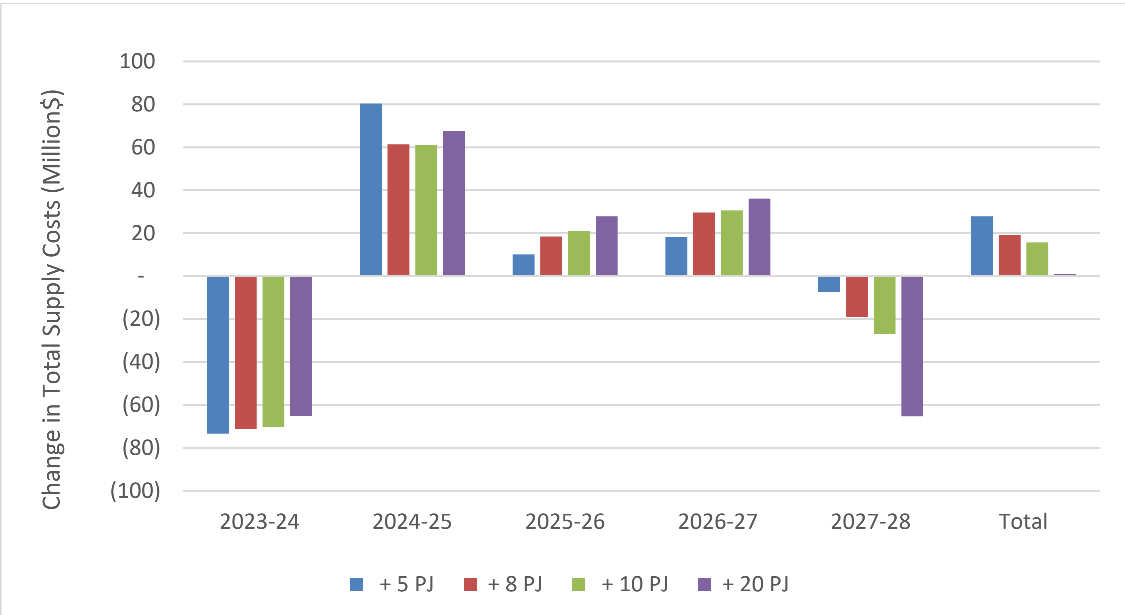
In order to confirm the results of the optimization analysis of storage capacity, ICF also evaluated the impact of different levels of storage capacity on supply portfolio costs for the Typical Weather scenario to assess the impact on supply portfolio costs. This was done to assess total portfolio cost impacts based on holding different levels of incremental storage capacity constant over the 5-year period. The results of the analysis are shown below.

As indicated in Exhibit 1-4, in the Typical Weather scenario, additional storage capacity reduced overall costs in 2023/24 and in 2027/28, but resulted in an increase in costs in 2024/25, 2025/26, and 2026/27. Over the 5-year period, total costs were relatively flat across the range of incremental storage capacity. As outlined in Exhibit

[10] The costs in Exhibit 1-3 reflect the incremental storage capacities outlined in Exhibit 1-2

4-13, costs changed between 0.008% and 0.2% relative to the total supply portfolio cost depending on the amount of incremental storage capacity. This is in line with expectations given the price of storage capacity used in the analysis reflects actual storage contracts signed in the recent past, where we would anticipate that the storage cost reflects the value associated with the storage capacity.

Exhibit 1-4 : Impact of incremental storage capacity on Total Supply Portfolio Costs (Million$) in the Typical weather cases



1.5 Recommendations and Conclusions

Enbridge Gas estimated an aggregate excess storage capacity for bundled service customers of 203 PJ for the 2023-24 storage year. This value increases to 208 PJ by the 2027/28 storage year based on projected natural gas demand growth within this customer group. Given 185 PJ of utility owned storage capacity valued at the cost of service, this would require 18 PJ of market-based storage in 2023/24, increasing to 23 PJ of market-based storage in 2027/28.

Based on our assessment of storage economics and the value of storage in reducing customer cost volatility, ICF would consider the estimate of the Aggregate Excess to represent a lower bound on the appropriate level of storage capacity needed to serve in-franchise bundled service customers rather than the optimal amount. The analysis of a lower storage capacity scenario indicates that the reduction in storage costs would be more than offset by increases in non-storage supply costs and the reduction in value resulting from the decrease in storage deliverability.

ICF's assessment of storage value under different weather conditions and time periods suggests that Enbridge Gas should hold a certain amount of additional market-based storage capacity above the level indicated by the Aggregate Excess methodology to meet design day system capacity requirements, to increase system reliability and reduce cost volatility to Enbridge Gas customers, and potentially to reduce overall costs to Enbridge Gas customers.

ICF's analysis indicates that the direct costs of holding incremental storage capacity are likely to be roughly offset by reductions in gas supply costs over a fairly broad range of incremental storage capacity. In the typical weather scenario, the direct benefits (reductions in supply costs) provided by storage continue to improve as additional storage is added to the portfolio up to the maximum level of incremental capacity (20 PJ) evaluated by ICF. However, the incremental benefits are modest and could be offset by increases in the cost of incremental storage capacity. As a result, the overall amount of incremental capacity that should be considered by Enbridge Gas will depend on the cost of the incremental storage at the time that Enbridge Gas goes into the market to acquire the storage, and the level of importance Enbridge Gas, the OEB, and other stakeholders place on maximizing supply reliability and minimizing cost volatility vs. the risk of holding excess storage capacity in years where the additional storage capacity does not provide incremental value.

ICF's analysis suggests that Enbridge Gas should consider increasing the amount of market-based storage capacity held for bundled service customers by about 10 PJ from 18 PJ to 28 PJ. This recommendation reflects a balance between cost, cost volatility, design day reliability, and minimizing up front contract cost commitments for supply services and reflects the results of the assessment of the value of storage under different weather conditions, and the assessment of the impacts of different levels of storage capacity on costs for the typical weather scenario. The recommendation is based on both the analysis of alternative weather scenarios, and the analysis of alternative storage capacity levels for the "Typical Weather" scenario.

2 Implications of Changes in Natural Gas Markets on Storage Value

ICF is forecasting significant changes in the value of natural gas storage over the next five years, with lower seasonal value during the next two to three years as natural gas prices generally decline from current high prices, followed by a significant increase in seasonal values after 2025. This section of the report reviews the changes in natural gas market conditions that ICF expects to impact the natural gas markets and the value of gas storage for Enbridge Gas. The first section presents an overview of ICF's North American natural gas market outlook. The second section is focused on the Canadian gas market, examining the potential shifts in inter-regional pipeline flows and natural gas prices. The third section looks at the impact of weather on natural gas storage scenarios and how ICF constructed its weather cases that Enbridge Gas used to evaluate various gas storage options.[11]

2.1 North America Gas Market Outlook

North American Demand Outlook

The ongoing Russia-Ukraine conflict as well as the rebound in market activities post covid pandemic are leading to continued growth in gas consumption and exports from North America. Through 2025, growth in North America demand is primarily export driven, and most of the expected exports are via LNG terminals and piped gas to Mexico. Natural Gas demand trends in Canada are expected to closely follow the rest of North America.

The power generation sector has also been a major driver of incremental gas consumption within North America. Even though prices of natural gas are currently higher than coal, we are seeing very limited gas to coal switching. Gas to coal switching has been limited due to relatively low coal stockpiles. Utilities appear to be limiting coal consumption to limit the drawdown on stocks due to potential shortages and delays in future coal deliveries. In addition, much of the coal capacity has retired in the past decade due to environmental regulations favoring natural gas-fired plants, which has reduced the potential to switch to coal during periods of high natural gas prices. There has also been increased coal demand from Western Europe as it has discontinued Russian supplies. As a result, power producers are using more natural gas rather than coal, leading to growth in power sector gas consumption.

As the economy has recovered from the pandemic shocks, gas consumption in the industrial sector has also increased given the uptick in the petrochemical and manufacturing sectors which are concentrated on the U.S. Gulf Coast. Industrial demand is projected to increase by about 9 percent by 2025 from the lows seen in 2021. Lately, markets are seeing a slacking demand growth due to an anticipated economic slowdown given the consistent high price environment

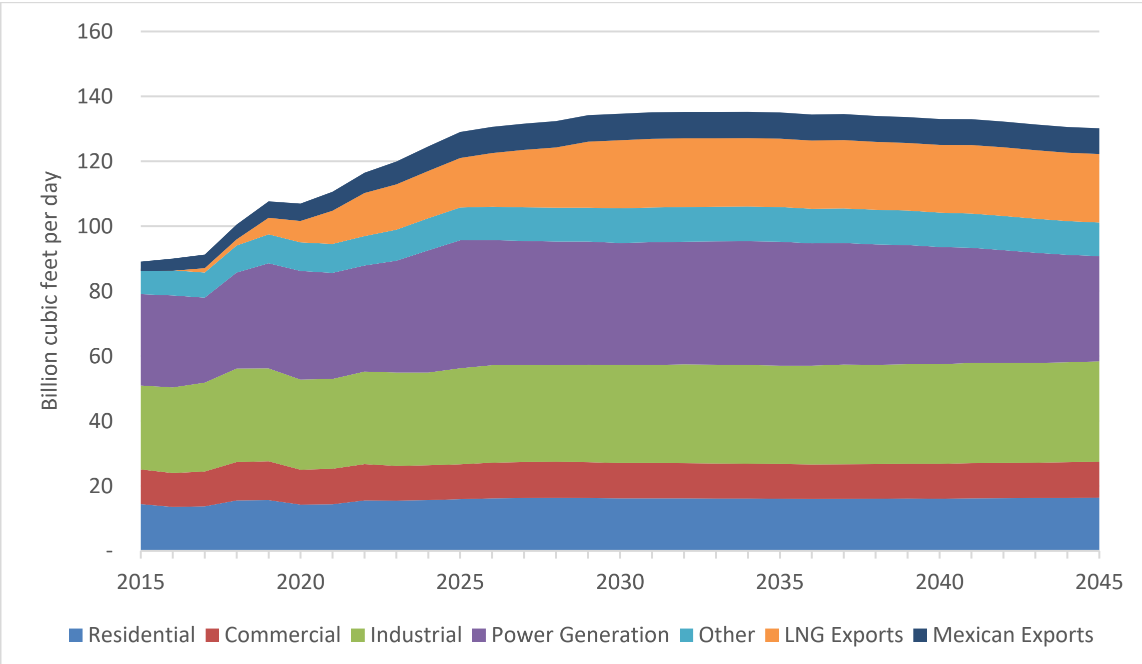
Residential and commercial gas demands are expected to rise only slightly, as increased demand due to the addition of new gas customers is partially offset by reductions in per-customer consumption due to energy efficiency improvements.

ICF's base case model includes carbon price assumptions reflecting known and anticipated North American carbon policy. ICF assumes charges on CO_2 emissions from the power sector for California and the RGGI states escalate throughout the forecast. Charges in other states (collectively) begin as early as 2022.

[11] The outlook and forecasts discussed in this section are those of ICF and may differ from views of Enbridge Gas in some respects.

Gas demand in Mexico is expected to increase sharply to meet growing power generation gas demand in Mexico. By 2025, ICF projects that pipeline export to Mexico will reach 8 Bcfd, 38% above the export volumes in 2021.

Exhibit 2-1 : US and Canada Natural Gas Demand by Sector

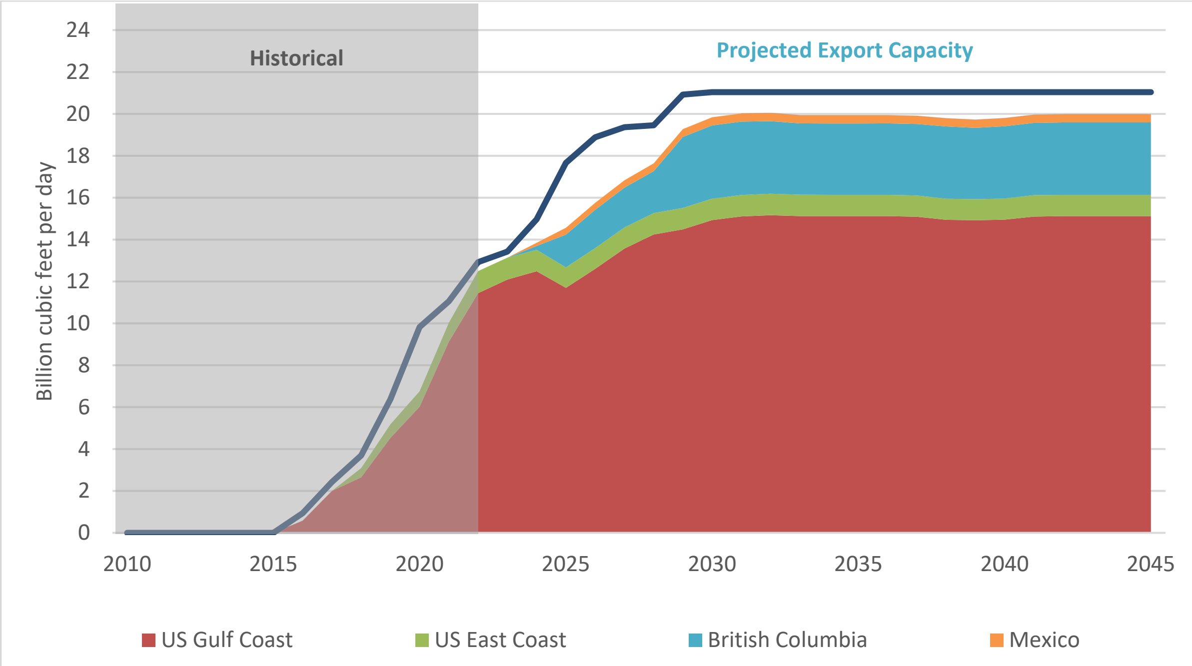


Source: ICF GMM®

ICF assumes that 12 North American LNG export terminals will be built and/or expanded: Sabine Pass, Freeport, Cove Point, Cameron, Corpus Christi, Elba Island, Golden Pass, LNG Canada, Woodfibre, Calcasieu Pass, Costa Azul, and Driftwood LNG. By the end of 2022, ICF projects U.S. LNG export capacity will be 12.9 Bcfd. ICF's current projection assumes total North American LNG exports reach 15.2 Bcfd by 2025, with the majority (13.9 Bcfd) coming from the U.S. Gulf Coast.

ICF assumes an additional 8.1 Bcfd of export capacity will come online in the U.S., Canada, and Mexico between 2022 and 2045 and the North American LNG export terminal capacity utilization is projected to average about 93% through 2045.

Exhibit 2-2 : LNG Export Volume versus Capacity



Source: ICF GMM®

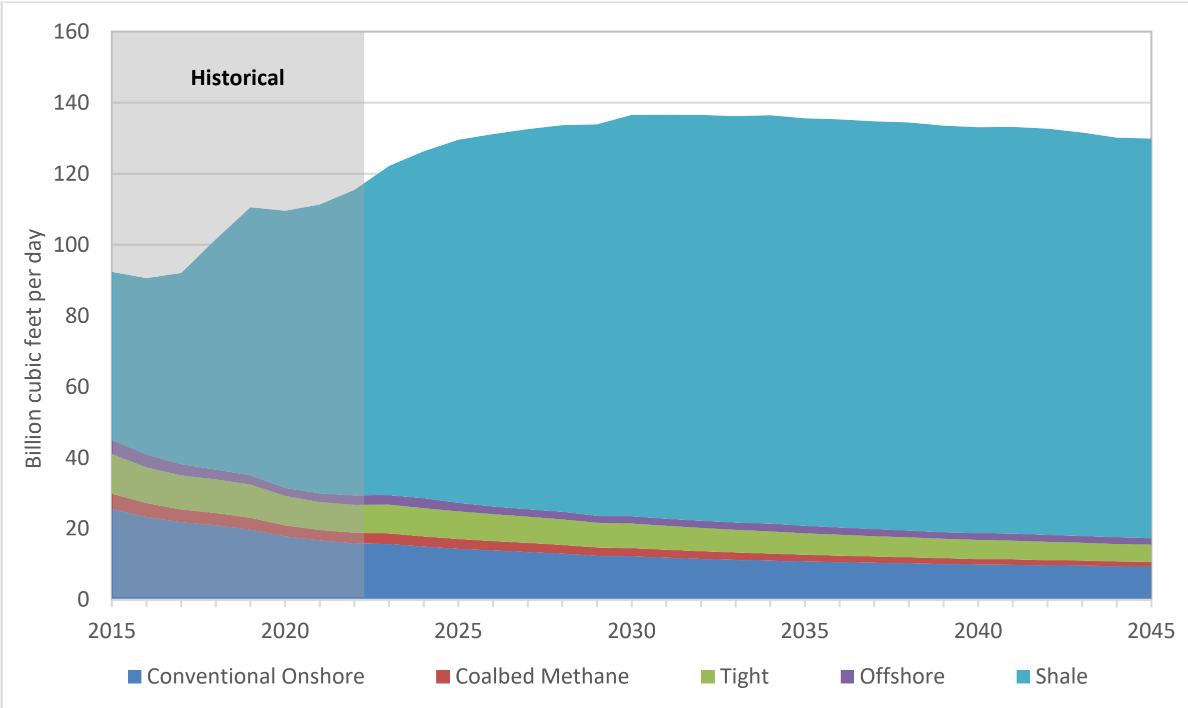
North American Supply Outlook

Over the past several years, natural gas production in the U.S. and Canada has grown quickly, led by unconventional production. Production is expected to grow further through 2030 and then expected to remain flat (see Exhibit B). Recent unconventional production technology advances (i.e., horizontal drilling and multi-stage hydraulic fracturing) have fundamentally changed supply and demand dynamics for the U.S. and Canada, with unconventional natural gas and tight oil production expected to far exceed declining conventional production.

Total U.S. and Canadian gas production is currently over 94 Bcfd, with the Marcellus/Utica accounting for over 30 percent of total North American production. Production growth has been centered in the Marcellus/Utica due to the size of the resource (estimated to be well over 1,000 trillion cubic feet) and low per-unit production costs. Natural gas production growth from the Marcellus and Utica has slowed down since lack of pipeline infrastructure is limiting movement of gas out of the basin.

Even though the oil prices are high, North American drilling activity is slower than expected in 2022 due to investor resistance to drilling expansion, lack of infrastructure, labor shortages and uncertain public policies pertaining to drilling in the US.

Exhibit 2-3 : U.S. and Canada Natural Gas Production



Source: ICF GMM®

North American Price Outlook

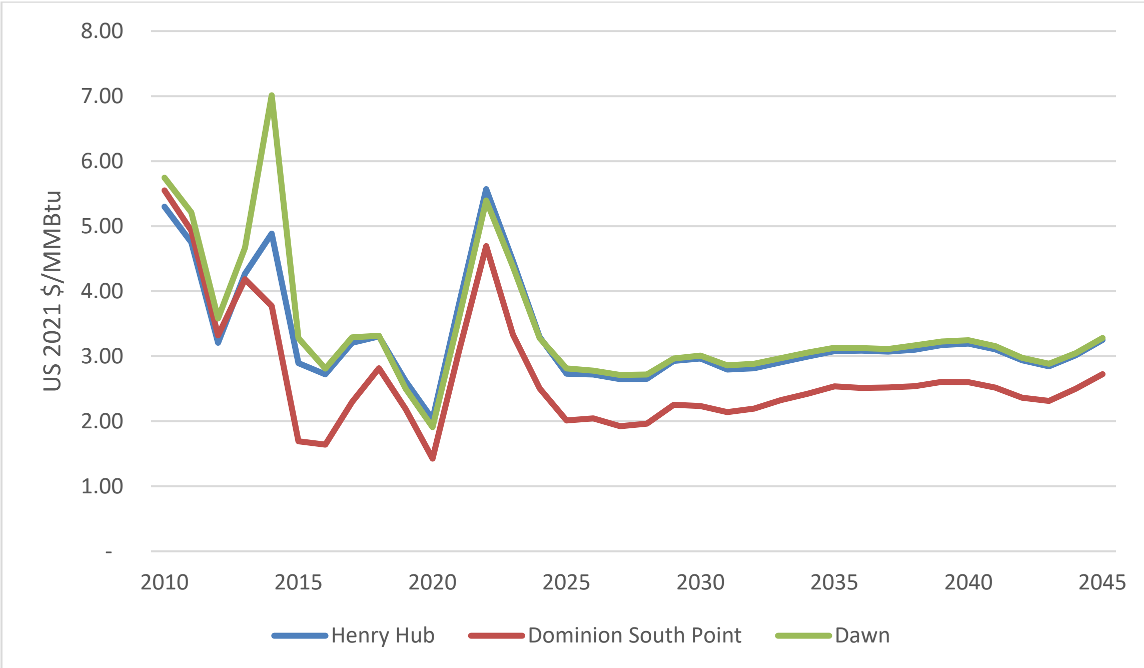
Natural gas prices at the major market hubs in North America are forecasted to be higher in 2022 than they were in 2021 due to a significant rise in LNG exports demand, low levels of natural gas in storage, slower than expected production gains and fluctuating weather.

ICF expects natural gas prices across North America to remain high in 2022 as well as 2023 given the current market conditions. The Henry Hub price is projected to average $5.57/MMBtu (in real 2021$) in 2022 and $4.47/MMBtu in 2023. Prices are expected to stay below $3.5/MMBtu in 2024-2025 (in real 2021$), under normal weather conditions, as natural gas markets rebalance with increased drilling and production activities. Between 2026-2045, prices are projected to stay between $2.65/MMBtu and $3.25/MMBtu (in 2021$).

The natural gas prices at Dawn in 2022 and 2023 are projected to average US$4.89/MMBtu amid the ongoing geopolitical tensions leading to increased demand and supply shortages. They will be under US$3.28/MMBtu from 2024 through 2030 and average about US$3.01/MMBtu (in 2021$) between 2025 and 2045.

Flows from Western Canada before 2037 and then from the Marcellus/Utica after 2037 coupled with higher gas demand in the Gulf Coast keeps the prices at Dawn near Henry Hub levels. ICF projects that Dawn will trade at a premium to Henry Hub between 2025 to 2045.

Exhibit 2-4 : Natural Gas Prices (US$) at Henry Hub, Dominion South Point, and Dawn



Source: ICF GMM

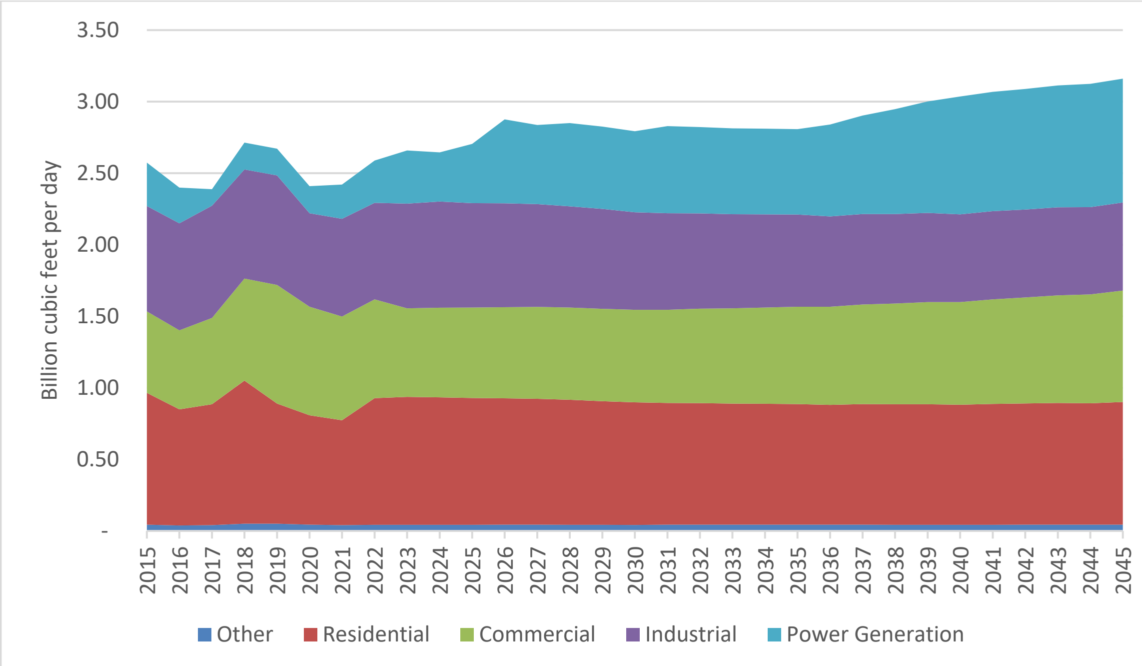
2.2 Ontario Natural Gas Market Outlook

Supply and Demand Trends

Ontario's natural gas demand in 2019 was about 2.7 Bcfd and accounted for approximately 21 percent of Canada's total natural gas demand. Demand growth was stunted between 2020-21 due to the Covid-19 pandemic but is expected to go back to the pre-pandemic levels by 2023. ICF projects Ontario's natural gas demand to average 2.9 Bcfd between 2025 to 2045.

Currently, the residential sector, which mainly relies on natural gas for space and water heating, has the largest demand for natural gas in Ontario and averages about 0.9 Bcfd annually for 2022. The residential, commercial, and industrial generation sectors together comprise over 85 percent of Ontario's natural gas demand. ICF's Q2 2022 base case expects power generation gas demand to experience the most growth during the next decade, increasing from 0.3 Bcfd in 2022 to 0.6 Bcfd in 2030. As nuclear power plants retire and access to gas from the Marcellus/Utica supply region of the U.S. improves, natural gas-fired power generation is projected to increase significantly.

Exhibit 2-5 : Ontario Natural Gas Demand



Source: ICF GMM® Case

Regional Supply Trends

Ontario has little natural gas production of its own, and thus imports practically all its supply from other regions in Canada and the United States. Ontario receives its natural gas from three main flow pathways, from Michigan, Western Canada and Niagara, with minimal volumes from Iroquois. In 2021, the largest regional supplier of natural gas to Ontario was Western Canada, which supplied 2.17 Bcfd on an average annual basis.

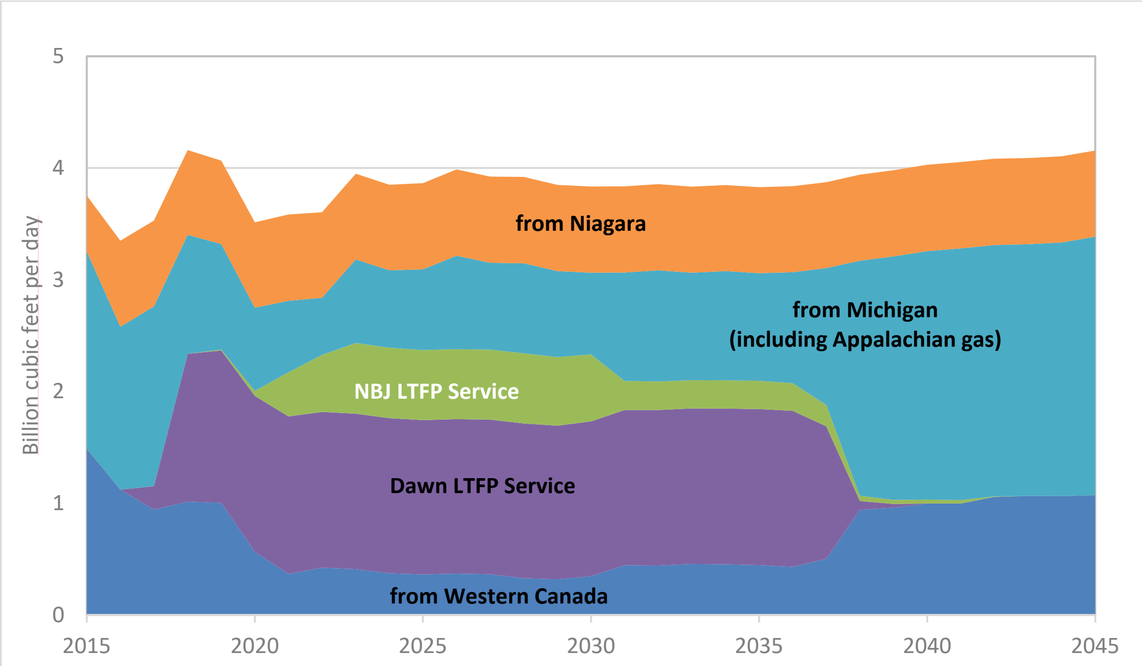
ICF projects that flows from Western Canada into Ontario will grow between 2022-2023, reaching 2.4 Bcfd by 2023 and then remain flat for the next couple of years before they start to decline in 2028.

The second biggest source of natural gas for Ontario is Michigan, which in turn sources its gas from the Midcontinent, Rockies, and the Marcellus/Utica supply region. In 2019, 0.95 Bcfd flowed from Michigan into Ontario. This was slashed by over 30 percent in 2021 due to lockdowns and reduced demand because of COVID-19 pandemic. Flows from Michigan to Ontario are projected to increase after the expiration of the Dawn LTFP service in 2037 and 2038[12]. The supply from Michigan will grow from 0.51 Bcfd in 2022 to over 2.1 Bcfd by 2038.

In recent years Marcellus/Utica gas has also been flowing northbound on the Tennessee and National Fuel pipeline systems to supply Ontario via the border crossing at Niagara, New York. By 2025 Ontario will receive 61 percent of its supplies from Western Canada, 19 percent via Michigan, and 20 percent via Niagara.

[12] The LTFP Services may be renewed prior to expiration.

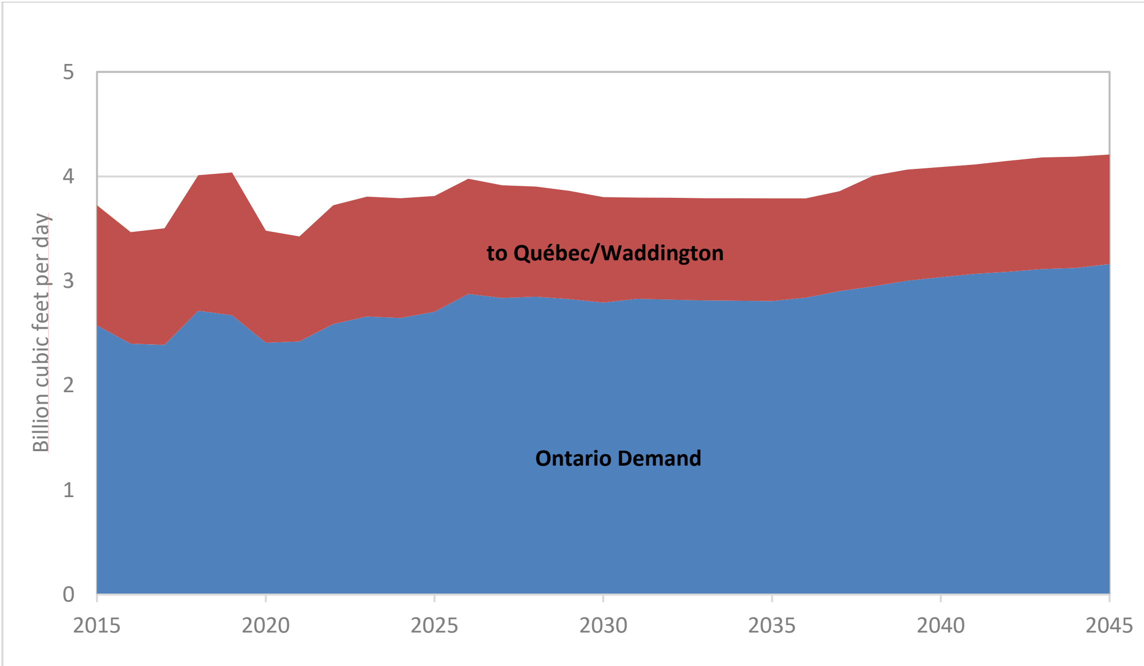
Exhibit 2-6 : Ontario Natural Gas Supply, Annual In-bound Flows



Source: ICF GMM® Case

Another important factor that will influence pipeline flows in Ontario will be the potential growth in New York and New England peak winter demand. Currently that demand growth is expected to be greater than the planned pipeline capacity additions from the Appalachian Basin directed toward that region. Flows from Ontario and Québec into the Northeastern U.S. will remain a critical component of peak period supply in the U.S. Northeast.

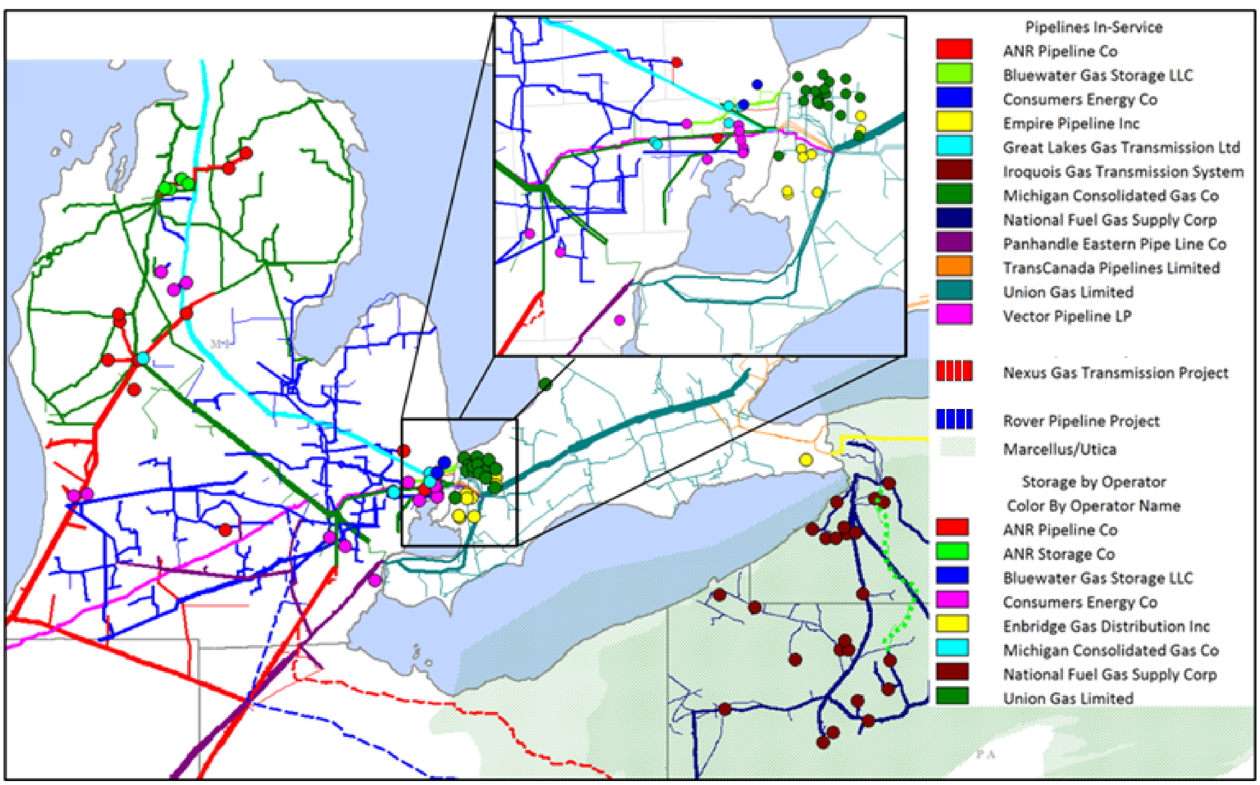
Exhibit 2-7 : Annual Ontario Demand and Out-bound Flows



Source: ICF GMM®

Exhibit 2-8 below presents a map of the infrastructure around Dawn (inset) and the pipeline network serving the broader geographic market, including storage facilities outside Ontario connected to the broader pipeline network.

Exhibit 2-8 : Pipeline and Storage Infrastructure for Ontario



Source: ABB Velocity Suite

Several pipelines that are interconnected within the broader North American gas market also feed into Dawn. These pipelines are summarized in Exhibit 2-9 below.

- Link Pipeline from EGD's Tecumseh storage field which also receives gas at the St. Clair River from the ANR pipeline that reaches back into Michigan, the Mid-Continent and Texas.
- Bluewater Pipeline feeds into Enbridge Gas at the St. Clair River, connecting Enbridge Gas to the Bluewater storage facilities in Michigan as well as to Great Lakes Pipeline, ANR, DTE Gas Pipeline (aka MichCon), and Vector Pipeline. Bluewater also offers its merchant storage customers the ability to take possession of their gas at Dawn rather than in Michigan.
- TC Energy feeds directly into the Dawn storage hub after receiving gas upstream from Great Lakes Pipeline at St. Clair River.
- The Vector Pipeline is directly connected to Dawn and reaches back to the Chicago area where the pipeline interconnects with Alliance. Vector has receipt points with ANR, DTE, Northern Border, Guardian, NEXUS, and Rover while at the Dawn end Vector connects with Enbridge Gas. Vector also interconnects with Bluewater Storage and Washington 10 Storage in Michigan. NEXUS leases capacity on Vector, allowing its customers to schedule deliveries directly to Dawn.
- DTE Gas Pipeline (MichCon) directly connects with the Dawn storage hub through Enbridge Gas at the St. Clair River. DTE pipelines are connected to production in Michigan, DTE storage facilities in Michigan, Vector, Panhandle, ANR, and NEXUS pipelines.
- Enbridge Gas also connects with the Panhandle Eastern Pipeline at Ojibway, near Windsor. Panhandle provides access to gas production in the Gulf Coast and Mid-Continent regions.
- At the other end of the system, Enbridge Gas pipelines are interconnected with TC Energy's pipeline at Kirkwall. TC Energy's line connects with the Niagara Line (National Fuel Gas, Eastern Gas, and Tennessee Gas Pipeline) at Niagara and the Empire pipeline at Chippawa. Tennessee Gas Pipeline (a Kinder Morgan company), which connects with TC Energy at Niagara provides access into the major storage fields around Ellisburg, Pennsylvania, and Marcellus production. All these pipelines are bi-directional. Today, the primary direction of flow is from New York to Ontario.

Exhibit 2-9 : Pipeline Routes and Capacity from United States to Ontario

MMcf/d	Michigan to Dawn					Northwest New York to Ontario			Total
Pipeline Route	Great Lakes (St. Clair) MI into Dawn	Vector St. Clair MI to Dawn	Panhandle to Union	Bluewater to Union	MichCon to Union	Niagara (TGP to ON)	Niagara (National Fuel to ON)	Empire into ON at Chippawa	
Pipeline Import Capacity	2,100	1,745	150	257	250	825			5,327
Pipeline	Great Lakes	Vector	Panhandle	Bluewater	MichCon	Tennessee Gas Pipeline	National Fuel Gas Supply	Empire Pipeline	
Owner	TC Energy	Enbridge Gas (60%) & DTE Energy (40%)	Energy Transfer Partners	Plains GP Holdings, L.P.	DTE Energy	Kinder Morgan	National Fuel	National Fuel	
Operator	Great Lakes	Enbridge Gas	Panhandle Eastern	Bluewater Gas Storage	DTE Energy	Tennessee Gas Pipeline	National Fuel	National Fuel	

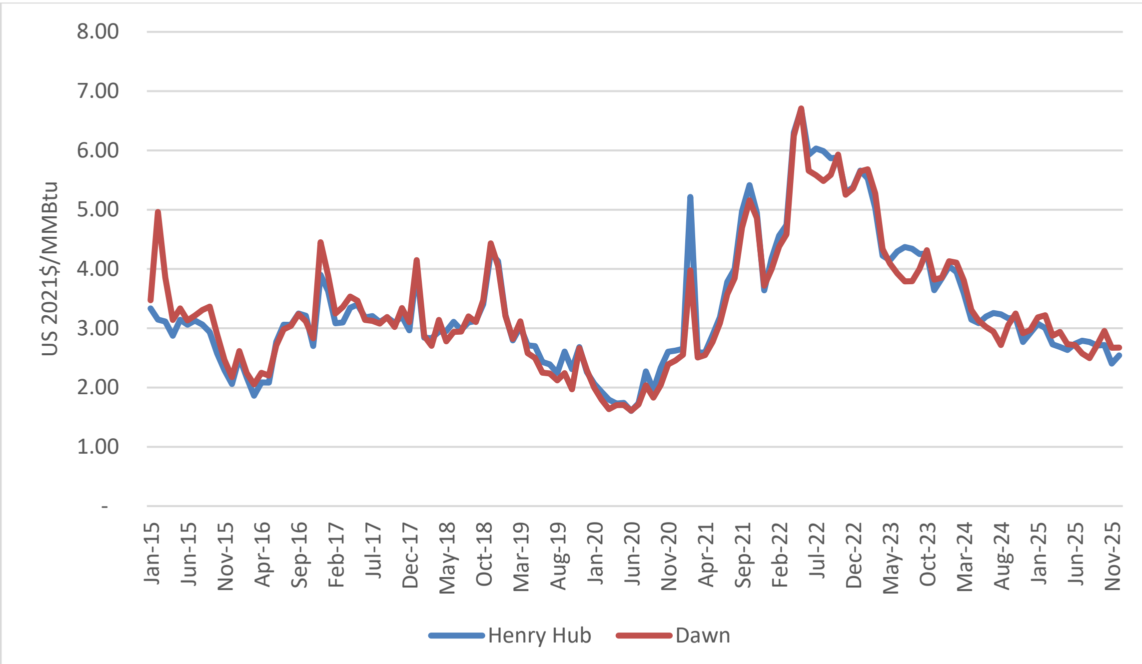
Source: ICF GMM®

***This table includes only capacity from Lower Peninsula MI to ON, and Western NY to ON*

2.3 Implications to Ontario Storage Values

The North American gas markets are in a period of transition. Gas prices in 2021 and 2022 have risen rapidly as the economy has rebounded from the recent pandemic and as international events have increased demand for LNG exports. Current natural gas prices are well above ICF's expectations for long term natural gas prices. ICF's April 2022 Base Case natural gas price forecasts for Henry Hub and Dawn used in this analysis are shown in Exhibit 2-10 below.

Exhibit 2-10 : ICF's April 2022 Base Case Monthly Gas Price (US$) Forecast for Henry Hub and Dawn



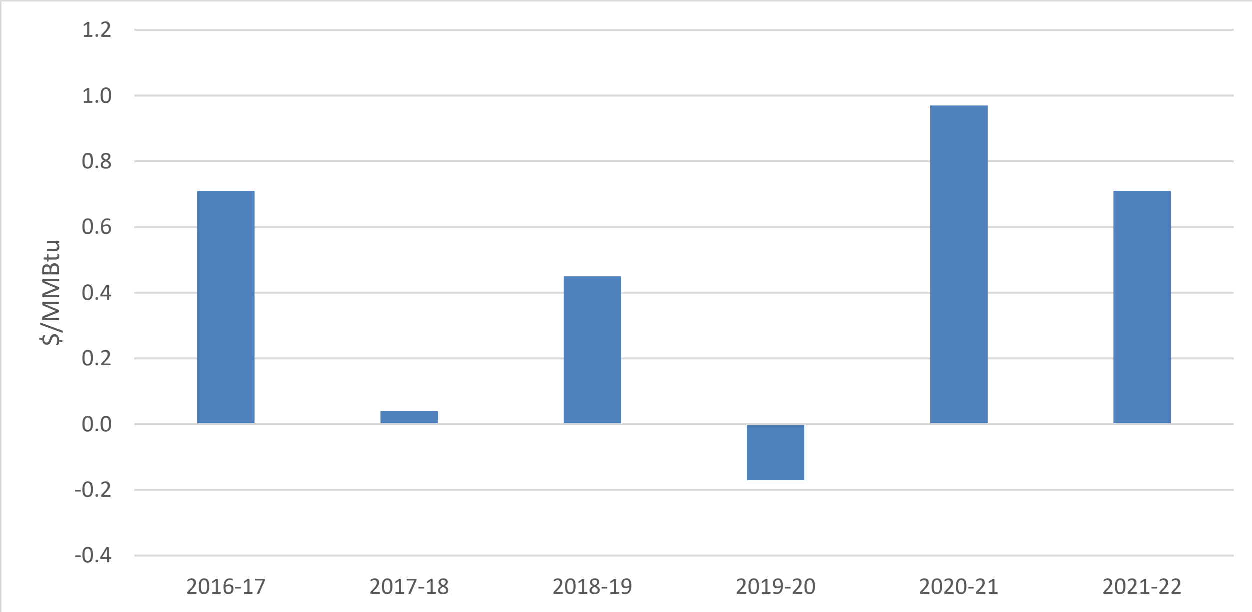
Source: ICF Gas Market Model

ICF projects that natural gas prices are likely to decline through 2025, before rebounding, and increasing slowly through 2035.

In the last year, gas price volatility has been much higher than longer term averages. ICF expects that the gas market will continue to exhibit increased gas price volatility. In the near term the increase in volatility is driven by uncertainty in international markets, and tightness in supply. Over the next two to three years, the impact of the increase in volatility will be partially offset by the impact of falling prices. In the longer term, the increase in volatility will act to further increase the value of holding natural gas storage.

Part of the value provided by natural gas storage is the ability to purchase lower priced natural gas during off peak periods to avoid the need to purchase gas during peak periods. In the case of the storage capacity used by Enbridge Gas to serve bundled service customers, this value is driven by seasonal changes in natural gas prices. As noted above, the seasonal changes in natural gas prices can vary widely from year to year. Exhibit 2-11 illustrates the swings in the seasonal value of natural gas at Dawn from the 2016/17 storage year through the 2021/2022 storage year.

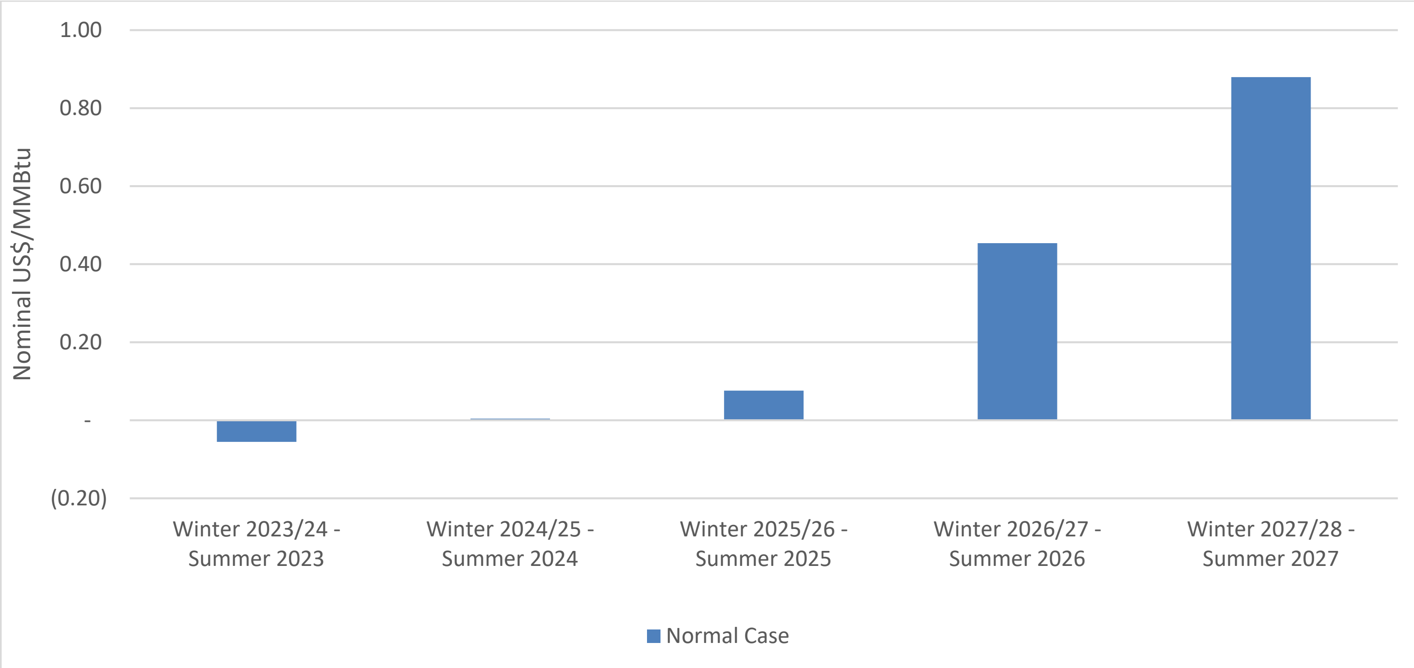
Exhibit 2-11 : Seasonal Natural Gas Price Spread at Dawn (US$/MMBtu)



Part of the variability in the seasonal natural gas price spreads is due to normal year to year market volatility related to differences in weather, supply trends, changes in natural gas exports and other seasonal factors. However, the seasonal storage values are also influenced by the longer year trends in natural gas market prices. When prices are generally increasing, the seasonal value of storage generally will be higher than average since winter gas prices are further up the increasing price path than summer prices, and when prices are generally decreasing, the seasonal value of storage generally will be lower than average since winter gas prices are further down the declining price path than summer prices.

In today's market, gas prices are higher than the long-term equilibrium price trend projected by ICF. As a result, ICF is projecting declining natural gas prices over the next couple of years, and ICF's forecast of seasonal gas price spreads are lower than average due to the projected declining natural gas price path. This trend suppresses the seasonal price spread during the 2022/23 through 2024/25 storage seasons in the ICF base case forecast.

Exhibit 2-12 : Difference between Winter and Summer prices at Dawn (US$/MMBtu)



The actual path of the price decline will be determined by market conditions, including weather, and geopolitical factors driving gas export demand that make it difficult to determine the time period where the decline in prices will occur. As a result, the price decline may occur sooner or later than projected by ICF, which will have significant impacts on the year seasonal price spread pattern in the future. ICF is currently projecting the price decline in 2022/2023 through 2024/25 to negatively impact seasonal price spreads at Dawn, although a more rapid decline in gas prices would concentrate the impact on seasonal basis into a shorter time period, potentially leading to an increase in the seasonal basis in the 2023/24 storage year if prices remain higher than expected through April 2024, or if prices fall more rapidly than expected prior to April 2023.

3 Alternatives to Market Based Storage Capacity

Enbridge Gas is proposing to use 218 PJ of storage capacity to serve in-franchise customers, including 203 PJ to serve bundled service customers. Of this, 185 PJ is utility owned cost-of- service based storage. Enbridge Gas also holds 18 PJ of market-based storage capacity to serve bundled service customers. One of the questions that Enbridge Gas asked ICF to address was whether there were viable market-based alternatives to the market-based storage capacity, and whether these alternatives would allow Enbridge Gas to hold less market-based storage capacity to serve bundled service customers. ICF concluded that there could be viable market-based alternatives to market-based storage capacity, but these alternatives would not be preferable to market-based storage capacity due to a combination of factors including economics, system reliability benefits including contributions to design day capacity planning, and reductions in supply cost volatility to consumers.

ICF considered two broad alternatives to the use of market-based storage capacity in the bundled service customer supply portfolio. The first approach was to hold additional pipeline capacity to serve the load served by the market-based storage. ICF recently reviewed the availability of pipeline capacity for Enbridge Gas as an alternative to the Dawn to Corunna pipeline. This review concluded that incremental pipeline capacity would be unlikely to be available or would require additional capacity on upstream pipelines to provide reliable winter service to Dawn and would not be a cost-effective alternative.[13] This conclusion remains valid for this analysis. In addition, the use of pipeline capacity to replace the existing market-based storage capacity would have resulted in a lower utilization rate for the pipeline capacity, increasing the costs relative to other options, and would not have reduced the long-term capital commitment relative to storage capacity. As a result, ICF does not consider incremental pipeline capacity to be an economic alternative to market-based storage.

The second alternative considered by ICF was the substitution of incremental purchases at Dawn for winter storage withdrawals, combined with winter peaking service to offset the storage contributions to design day. In this alternative, Enbridge Gas would reduce summer pipeline deliveries and summer purchases at Dawn and increase winter purchases at Dawn as the alternative to storage withdrawals. Enbridge Gas would also rely on purchases of delivered gas at Dawn to provide design day gas supply that otherwise would have been provided from the market-based storage capacity.

Dawn is a highly liquid market, and gas supplies at Dawn generally would be available for purchase. Enbridge Gas currently plans on purchases at Dawn to meet part of its supply portfolio requirements, including on a design day. Depending on the year, and depending on other market variables, including the price of market-based storage, the economics of purchasing gas at Dawn are roughly equivalent to the economics of holding market-based storage based on forecasted commodity costs. As a result, ICF considers this to be a potentially viable option for the replacement of market-based storage services. However, gas purchases at Dawn are not a perfect substitute for holding natural gas storage capacity. Storage capacity provides additional value relative to purchases at Dawn in several different areas.:

- Storage allows the purchase of gas to be shifted from the winter, when prices typically are higher, to the non-winter months when prices typically are lower.

[13] Assessment of the Value of the Enbridge Gas Dawn to Corunna Storage Project -Potential Value of Incremental Storage Capacity and Market-Based Alternatives for Enbridge Gas", ICF Resources, February 24, 2022, pages 31-35.

- Contribution of Storage Deliverability to Design Day Capacity Requirements. Storage deliverability provides a direct contribution to design day system capacity requirements. In the Gas Supply Planning model analysis, changes in storage capacity are addressed through incremental purchases at Dawn. However, purchases at Dawn do not have the degree of reliability provided by storage deliverability. The difference in reliability provides significant economic benefit to the use of incremental storage that is not captured in the Gas Supply Planning model analysis.

Increasing the reliance on winter purchases at Dawn as an alternative to holding incremental market-based storage would have significant implications on gas purchase costs. The expected increase in gas purchase costs associated with a shift from summer gas purchases to winter gas purchases would offset much or all (depending on the year) of the cost savings associated with the reduction in contracted storage capacity. In addition, the deliverability of the market-based storage capacity would need to be replaced to meet design day supply criteria. ICF's analysis suggests that during some years, reliance on winter purchases at Dawn could reduce the overall supply costs to Enbridge Gas's bundled service customers. However, in other years, this approach would lead to significant increases in costs. As a result, the reliance on increased winter purchases at Dawn would increase year-to-year gas supply cost volatility to Enbridge Gas's bundled service customers.

The reduction in the reliance on market-based storage would also impact design day planning. One of the trade-offs associated with reducing market-based storage capacity is the requirement to offset the loss of deliverability provided by the market-based storage on a design day. The most reliable market-based approach to replacing the storage deliverability likely would be delivered services provided at Dawn. Delivered Services are products offered by third parties that have firm contractual rights to pipeline capacity or storage deliverability and are willing to sell the capacity/deliverability for short durations (10 to 30 days) to meet peak demand requirements.

Delivered services are frequently relied on by utilities that have rapidly growing demand to meet incremental capacity requirements during periods when new pipeline capacity is unavailable. Delivered services contracts are generally signed for a year at a time, with no continuing obligation to provide the service beyond the contract year, and no assurances of future prices or availability.

Enbridge Gas currently relies on a significant volume of delivered services and purchases at Dawn to meet design day gas requirements in its supply plans and decreasing the market-based storage likely would further increase this reliance.

Given the liquidity of the market at Dawn, delivered service contracts likely would be available to offset the reduction in deliverability associated with a decline in contracted market-based storage. However, the cost of the delivered services contracts would further offset any potential cost savings associated with a reduction in market-based storage capacity. In addition, the cost and availability of the delivered service contracts likely will vary widely from year-to-year, leading to further increases in supply cost volatility impacting bundled service customers.

3.1 Projected Impact of Reducing Storage Capacity on Enbridge Gas' Supply Portfolio Value

In order to assess the impact on the supply portfolio of reducing storage capacity, Enbridge Gas ran the Supply Model with a 5 PJ decrement relative to the amount of storage capacity indicated by the Aggregate Excess methodology for each of the four weather scenarios evaluated. [14]

The results of the analysis indicate that reducing storage capacity below the level indicated by the Aggregate Excess methodology would result in reductions in storage demand charges. However, under the different weather scenarios, the storage demand charge savings are more than offset by the increased cost of purchasing gas supply in the winter months and peak day deliverability.

Based on this analysis, ICF determined that reducing storage capacity below the Aggregate Excess level likely would lead to an increase in the effective cost of the Enbridge Gas' supply portfolio. The results of the analysis and portfolio cost increases resulting from the 5 PJ decrement are shown in Exhibit 3-1 below:

Exhibit 3-1 : Impact of a 5 PJ Reduction in Storage Capacity on Gas Supply Portfolio Costs

Impact of Reduction in Storage Capacity on Gas Supply Portfolio Cost						
(CAD$Millions)	2023/24	2024/25	2025/26	2026/27	2027/28	Annual Average
Supply Model Portfolio Costs - Base Case Storage Capacity						
Normal Weather	3,168	2,623	2,452	2,580	2,533	2,671
Warmer than Normal Weather	2,892	2,712	2,089	4,013	2,740	2,889
Typical Weather	2,895	3,424	2,432	1,632	2,397	2,556
Colder than Normal Weather	3,291	2,909	2,881	2,700	1,773	2,711
Supply Model Portfolio Costs - 5 PJ Reduction in Storage Capacity						
Normal Weather Scenario	3,164	2,620	2,449	2,579	2,535	2,670
Warmer than Normal Weather Scenario	2,860	2,729	2,069	4,048	2,742	2,890
Typical Weather Scenario	2,875	3,448	2,425	1,612	2,415	2,555
Colder than Normal Weather Scenario	3,318	2,908	2,912	2,701	1,759	2,720
Cost of Replacing Lost Deliverability[15]	2.05	2.05	2.05	2.05	2.05	2.05
Impact of Reduced Storage Capacity on Portfolio Cost						
Normal Weather Scenario	(1.6)	(1.5)	(1.2)	1.4	4.2	0.2
Warmer than Normal Weather Scenario	(30.2)	19.9	(17.6)	36.9	4.1	2.6
Typical Weather Scenario	(17.8)	25.8	(5.6)	(18.1)	20.0	0.9
Colder than Normal Weather Scenario	28.9	1.3	32.7	3.6	(11.8)	11.0

As illustrated in Exhibit 3-1, decreasing storage by 5PJ results in average annual portfolio cost increases from a range of $0.2 million to $11.0 million, depending on the weather scenario being evaluated.

[14] The alternative weather scenarios are discussed in Section 4 of this report.
[15] The estimated value of the increase in deliverability and the value that would be derived from the increase in daily gas supply purchasing flexibility are documented in Appendix E.

4 Value of Incremental Storage Capacity to Enbridge Gas Bundled Service Customers

ICF used the analysis of North American and Ontario natural gas markets, combined with the assessment conducted by Enbridge Gas on the company's gas supply portfolio costs, to assess the impact of potential increases in natural gas storage capacity held by the company on the utility's overall gas supply portfolio cost under a variety of different weather scenarios. The analysis is summarized below.

4.1 Approach

The analysis was conducted in six steps:

1) ICF reviewed the Aggregate Excess Approach used by Enbridge Gas and estimated the amount of storage capacity consistent with the Aggregate Excess Approach based on the forecast of in-franchise bundled service demand provided by Enbridge Gas.
2) ICF specified four alternative weather scenarios to assess the impact of real-world weather on the storage capacity.
3) ICF assessed the impact on the Enbridge Gas In-franchise bundled service customer supply portfolio of reducing storage capacity below the level indicated by the Aggregate Excess Methodology. This analysis included an assessment of reducing storage capacity by 5 PJ below the level indicated by the Aggregate Excess methodology to determine the potential cost impacts of replacing storage capacity with purchases at Dawn. This analysis is reviewed in Section 3.
4) Enbridge Gas used their Supply Planning Model to evaluate the optimum storage and supply portfolio for each weather scenario.
5) ICF specified four alternative storage capacity scenarios for the Typical Weather scenario, and Enbridge Gas used their Supply Planning Model to evaluate total supply portfolio costs for each level of storage capacity.
6) ICF used the results of the Enbridge Gas's Supply Planning Model analysis of supply portfolio costs to evaluate the impact of changes in natural gas storage capacity on Enbridge Gas supply portfolio costs.

Each of these steps is described in more detail below.

4.2 Review of the Aggregate Excess Methodology

Historically, Enbridge Gas has used an aggregate excess approach to determining storage requirements, with minor differences[16] between the methodology used by EGD and Union. According to the OEB, "The aggregate excess method is the difference between the amount of gas a customer is expected to use in the 151-day winter period and the amount that would be consumed in that period based on the customer's average daily consumption over the entire year."[17]

[16] The Union approach uses only end-use demand when calculating aggregate excess, whereas the EGD approach uses system demand, including items such as lost-and-unaccounted for gas and own use gas.
[17] Ontario Energy Board, "Motions to Review the Natural Gas Electricity Interface Review Decision – Decision with Reasons" May 22, 2007. Page 59.

In essence, the aggregate excess methodology provides an estimate of the amount of storage capacity needed to optimize the utilization of contracted pipeline assets and minimize the uncertainty associated with meeting natural gas demand under normal weather conditions.

The aggregate excess approach is based on demand, rather than on the economics of storage and pipeline capacity. In and of itself, the aggregate excess methodology does not determine the optimal amount of storage capacity needed to minimize long term supply costs.

- In a market with significant excess pipeline capacity or other sources of winter gas supply being available at costs that are lower than the cost of meeting winter demand with storage, the aggregate excess methodology could result in a higher cost supply portfolio than holding a lesser amount of storage.
- In a market where prices and demand are more volatile than the normal conditions used to assess the amount of aggregate excess, and where there is limited available winter pipeline capacity or supply, or the available supply is higher cost than storage, the aggregate excess methodology could underestimate the amount of storage that should be held in an optimal supply portfolio.

The Aggregate Excess methodology is designed around normal weather. During some years, total supply costs might be lower if storage levels below the aggregate excess are included in the portfolio, and in other years, the supply costs might be lower if storage levels above the aggregate excess are included in the portfolio.

In the Ontario market, the seasonal swings in price, combined with the limited availability of incremental pipeline capacity into the storage region, and the low cost of service-based storage capacity included in the aggregate excess methodology, ICF expected that the Aggregate Excess methodology would represent the floor on the appropriate level of storage capacity. To test this hypothesis, ICF asked Enbridge Gas to provide a series of Gas Supply Planning model runs for the normal weather case and for a set of alternative weather scenarios where additional market-based storage capacity was available as part of the solution. The results of this analysis are presented in Section 4.4 and 4.5.

4.3 Alternative Weather Scenarios

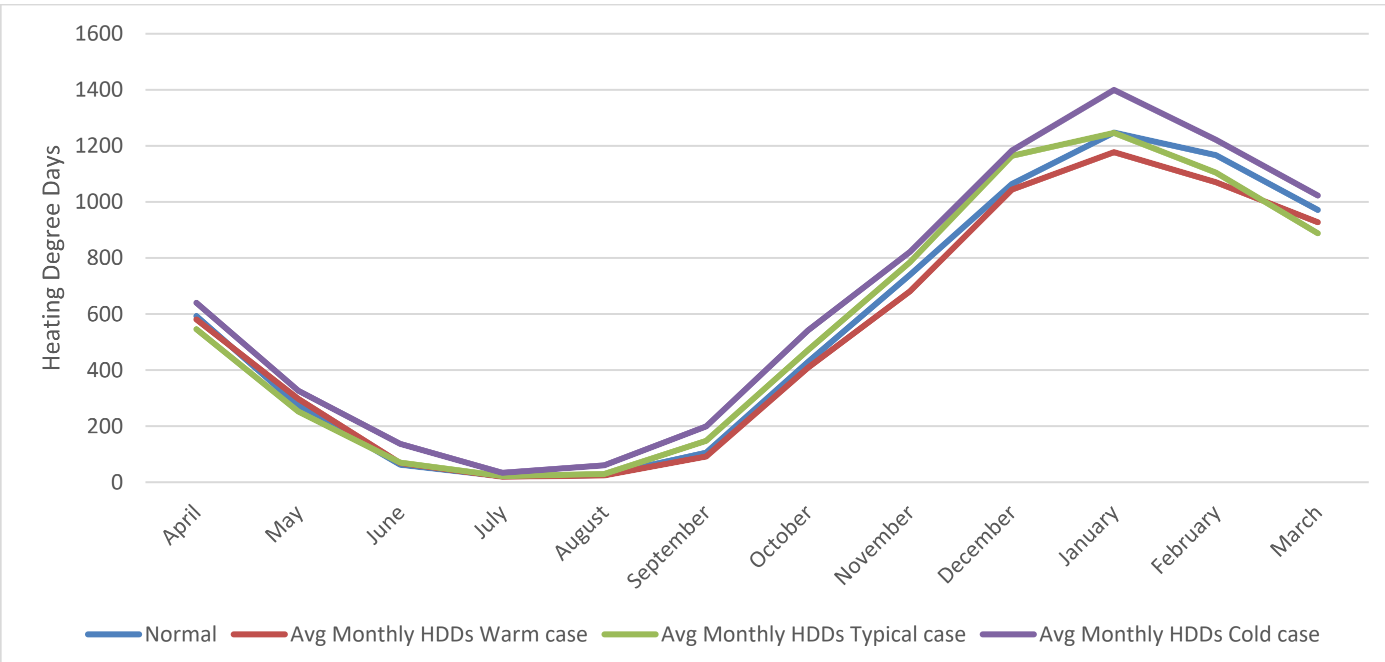
The calculation of Aggregate Excess is based on a demand forecast reflecting normal weather. The assessment of storage value for the normal weather case is influenced by two major storage drivers. The first is that normal weather analyses tend to understate the impact of market volatility on storage value. Much of the natural gas price volatility observed in the market is due to weather variation that is not captured in an analysis based on normal weather conditions. The second major point is that current market conditions impact short term forecasts. In the current natural gas market, natural gas market prices are higher than the long-term equilibrium price levels. As markets correct, the decline in prices tends to suppress the seasonal storage values calculated based on projected seasonal natural gas prices. However, the timing of the correction is uncertain, and the timing of the related changes in storage value is uncertain.

Standard variation in weather will lead to different storage valuations. During some years, total supply costs might be lower if storage levels below the aggregate excess are included in the portfolio, and in other years, the supply costs might be lower if storage levels above the aggregate excess are included in the portfolio. Incremental storage generally acts to mitigate the impacts of extreme weather conditions.

In order to provide a more realistic assessment of storage value, ICF developed a series of alternative weather scenarios. Each weather scenario was used to evaluate the Enbridge Gas' supply portfolio costs for the 5-year period from April 2023 through March 2028.

ICF used its April 2022 Gas Market Model (GMM) Base Case as the starting basis for its evaluation of the North American natural gas markets and Enbridge Gas' gas storage planning. The GMM is an internationally recognized model of the North American gas market that includes projections for natural gas demand by sector, conventional and unconventional natural gas resources, production costs, and other major gas market developments, such as potential Liquefied Natural Gas (LNG) exports. The GMM projects monthly natural gas demand, supply, and prices for more than 120 regions and is a general equilibrium market model. The model is described in more detail in Appendix C. ICF used the GMM to conduct sophisticated analysis of the potential impacts and risks associated with alternative weather scenarios on natural gas demand and prices.

Exhibit 4-1 : Average HDDs in Ontario between April 2023 to March 2028 between the alternate weather cases and normal case

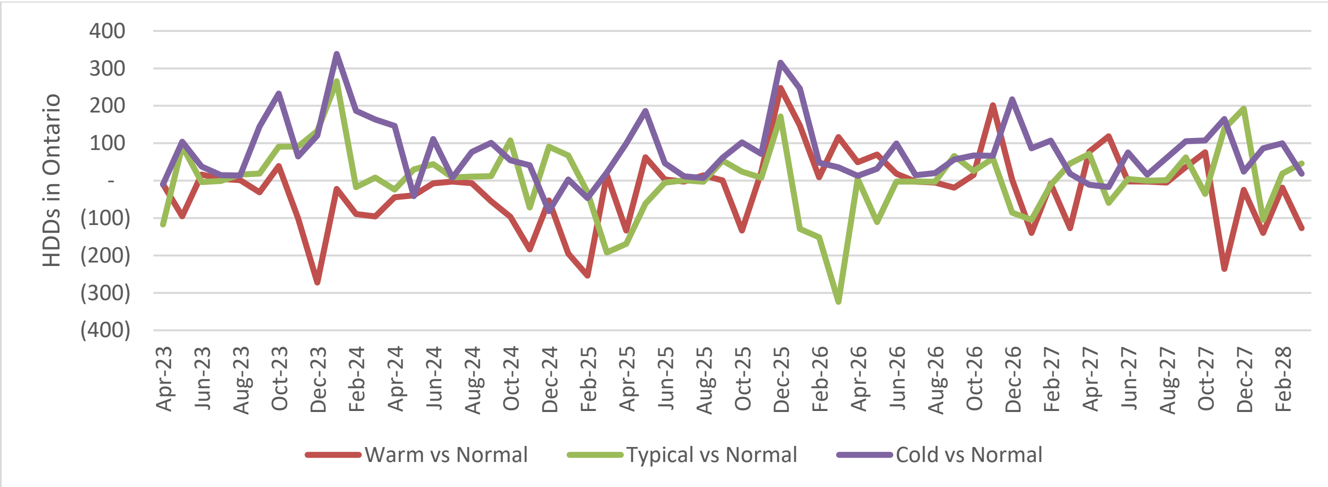


Source: ICF GMM® Case

To assess the impact of colder than normal and warmer than normal weather on prices, ICF ran 40 cases of actual 5-year weather patterns in the GMM to assess the volatility in prices with change in weather patterns.

The use of actual weather scenarios is important for estimating the actual range of impacts due to the range of positive and negative correlations between weather patterns in different regions of North America. This weather sensitivity analysis forms the basis needed to evaluate the company's gas storage operations and the impact of weather volatility on natural gas prices and basis at the natural gas market centers considered important by Enbridge Gas.

Exhibit 4-2 : Variation in the HDDs in Ontario between the alternate cases and the normal case



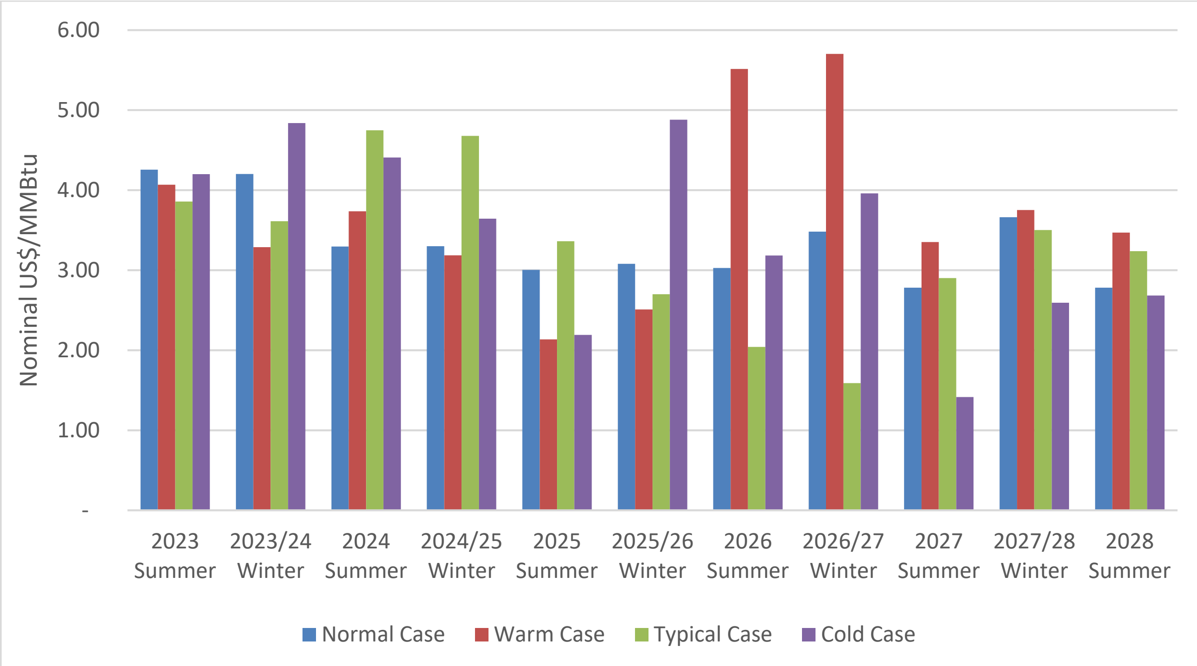
Source: ICF GMM® Case

The normal weather scenario is based on the average of the monthly HDD and CDD data for each month over the 20-year period from 2002 to 2021. ICF selected GMM's base case from April 2022 to define the normal weather scenario. The Warmer than normal weather scenario reflects an actual five-year weather period where the HDDs were lower than the normal (base) weather conditions. The Typical weather scenario is based on five years of actual weather that in total was the closest to the normal weather scenario. The Colder than normal weather scenario is based on five years of actual weather data with HDDs higher than the normal weather scenario. The three alternate weather scenarios are summarized below:

- For the **Warmer than normal Weather Scenario,** ICF selected the warmest 5-year period in Ontario[18] between 1980 to 2020 using the actual monthly HDD data. Based on this approach, 2015 – 2019 turned out to the case with lowest HDDs.
- For the **Typical Weather Scenario,** ICF selected the weather scenario which was closest to the normal weather scenario. Based on this, 2008 - 2012 turned out to be the scenario where the Ontario HDDs were closest to the normal scenario.
- For the **Colder than normal Weather Scenario,** ICF selected the coldest 5-year period in Ontario between 1980 to 2020 using the actual monthly HDD data. Based on this approach, 1981 - 1985 turned out to the case with highest HDDs.

[18] The coldest and warmest five-year periods in Ontario correspond to the coldest and warmest five-year periods in North America (U.S. and Canada).

Exhibit 4-3 : Dawn Prices (Nominal US$) Under the Four Enbridge Gas Weather Scenarios



Source: ICF Gas Market Model

The three cases based on actual weather all show significant variation in year-to-year price patterns. The year-to-year variability in prices in these three cases is due:

- Year-to-year variability in the actual weather patterns. Even during the warmest 5-year period, some years are significantly colder than the other years in the sequence leading to increases in prices. And in the coldest 5-year period, the warmer years lead to a certain amount of cycling in natural gas prices.

- Changes in market conditions due to changes in demand and prices. In the near term, natural gas market prices tend to fluctuate around a longer term normal as the market responds to price induced changes in demand and supply, and to changes in storage inventory levels created by the changes in demand. And storage inventories fluctuate around the normal seasonal levels due to changes in demand and prices, leading to year-to-year fluctuations in prices.

- Differences between Ontario weather patterns and broader North American (U.S. and Canada) weather patterns lead to regional pricing patterns that can differ from the Ontario weather patterns.

Even in the Warm Case, the price variability increases. As illustrated in Exhibit 4-2, HDD's in the warm case are higher (e.g., colder weather) than in the other cases during certain time periods, leading to increased demand and higher prices. As a result, even the warmest five-year period lead to increases in prices during certain time periods, and higher price volatility than in the normal weather case.

Alternative Storage Scenarios

The four different weather scenarios lead to significant changes in natural gas commodity prices, including both the absolute prices and the price volatility. These commodity price outlooks across the Normal, Warmer than Normal, Typical, and Colder than Normal weather cases were provided to Enbridge Gas by ICF. Enbridge Gas then used these results to assess the impact of alternative storage scenarios on Enbridge Gas natural gas supply portfolio costs using the Enbridge Gas's Supply Planning model.

The analysis uses a base gas supply portfolio which represents the bundled demand and assets that Enbridge Gas is including in its Application. The base portfolio is underpinned by the Enbridge Gas demand forecast, and upstream contract costs at the time of developing the Enbridge Gas Application. In order to complete an analysis of incremental storage, Enbridge Gas first modeled three 10 PJ tranches of incremental market-based storage and included them in the base portfolio. Enbridge Gas assumed each 10 PJ tranche was 5% more expensive than their most recent market-based storage contract[19] and assumed the contracting parameters of a standard market-based storage contract, such as 1.2% maximum deliverability and 0.75% maximum injectability. For the purposes of this analysis, Enbridge Gas assumed that the gas storage would be available at or near Dawn.[20]

Once the incremental storage tranches were included in the base portfolio, Enbridge Gas ran the Gas Supply Planning model using the application's Resource Mix optimization function for each commodity price forecast provided by ICF. With the Enbridge Gas Supply Planning model optimizing using the SENDOUT© Resource Mix function and assuming each of the ICF commodity price forecasts, the Gas Supply Planning model was used to determine what level of incremental storage, if any, provided a lower cost portfolio than the base portfolio. ICF used the results of this analysis to assess the value of holding incremental natural gas storage capacity beyond the levels currently held by Enbridge Gas for bundled in-franchise customers.

4.4 Optimized Storage Capacity for Different Weather Scenarios

Resource Mix Optimization – Total Portfolio Cost

ICF evaluated the results of the Gas Supply Planning model runs to determine the value of incremental natural gas storage capacity for each of the four weather scenarios. Exhibit 4-4 shows the maximum base storage capacity by year between the four weather scenarios. Enbridge Gas assumes 203 PJ of storage capacity across the scenarios in all the 5 years. Under normal weather conditions, the Gas Supply Planning model selected incremental storage capacity in the solution in one out of the five years evaluated. The reduction in supply costs during this one year more than offset the increase in cost of holding the incremental market-based storage capacity,

We can infer that the model is about right on Aggregate Excess storage capacity in the normal weather case and there may not be any value in procuring additional storage. However, the Warmer than normal weather case as well as the Colder than normal weather case procured incremental storage capacity in three out of the five years. The typical weather scenario picked up incremental storage in two out of the five years The results of the analysis of alternative weather patterns supports the hypothesis that the Aggregate Excess methodology generally understates the optimal amount of storage capacity that should be included in the long-term Enbridge Gas supply portfolio.

[19] The most recent market-based physical storage contract of EGI has a capacity cost of $0.83/GJ. The demand charges incurred on Tranche One (10 PJ) was $0.87/GJ, Tranche Two (10 PJ) was $0.92/GJ and Tranche Three (10 PJ) was $0.96/GJ. The variable charges for injection or withdrawal were also based off of EGI's most recent physical storage contract, which is $0.006/GJ for either injection or withdrawal.

[20] For the analysis, Enbridge Gas has assumed that new storage is available at or near Dawn and does not require incremental pipeline capacity. Hence, the Enbridge Gas's Gas Supply Planning model analysis does not include any changes to the upstream transportation portfolio, resulting in fixed transportation costs across all scenarios.

Exhibit 4-5 is a summary of the costs associated with the 203 PJ storage capacity as calculated using the Aggregate Excess methodology. Exhibits 4-6 to 4-9 outline the cost impacts of adding incremental storage outlined in Exhibit 1-2 by incremental storage cost, supply cost, transportation cost and the total supply portfolio costs by year for each of the weather scenarios.

Exhibit 4-4 : Total Existing and incremental storage (PJ) in each of the weather scenarios by year

Optimized Storage Capacity (PJ)	2023/24	2024/25	2025/26	2026/27	2027/28
Aggregate Excess Capacity					
Normal Weather Case	203	203	203	203	203
Warm Weather Case	203	203	203	203	203
Typical Weather Case	203	203	203	203	203
Cold Weather Case	203	203	203	203	203
Incremental Storage Capacity					
Normal Weather Case	-	-	-	-	10.5
Warm Weather Case	-	-	25.9	30.0	3.4
Typical Weather Case	-	19.1	-	-	25.3
Cold Weather Case	3.2	-	30.0	-	12.5
Total Optimized Storage Capacity					
Normal Weather Case	203	203	203	203	213
Warm Weather Case	203	203	229	233	206
Typical Weather Case	203	223	203	203	229
Cold Weather Case	206	203	233	203	215

Exhibit 4-5 : Total Costs when Incremental Storage is provided to each of the scenarios (Million CAD$)

Total cost (Million CAD$)	2023/24	2024/25	2025/26	2026/27	2027/28	Annual Average Total Cost
Normal Case	3,168	2,623	2,452	2,580	2,531	2,671
Warm Case	2,892	2,800	2,144	3,835	2,740	2,882
Typical Weather Case	2,991	3,315	2,432	1,632	2,385	2,551
Cold Case	3,272	2,940	2,710	2,700	1,764	2,677

The total supply portfolio costs can be broken down by Storage cost, Supply cost, and Transportation cost as provided by the Enbridge Gas using their Gas Supply Planning model results. Based on these results, ICF was able to access the change in storage, supply and transportation costs between the existing base storage capacity case and the incremental storage capacity cases. The results from the same are shown in the Exhibit 4-6 to Exhibit 4-9 below.

When additional storage capacity is provided to the model, the total supply portfolio costs go down which is driven by the decline in the supply costs associated with the procurement of more storage.

Exhibit 4-6 : Incremental Storage Costs (Million$) by year between the weather scenarios

Incremental storage costs (Million$)	2023	2024	2025	2026	2027	Annual Average
Normal Case	(0.0)	0.0	(0.0)	(0.0)	10.4	2.1
Warm Case	0.0	1.1	28.0	31.9	3.4	12.9
Typical Weather Case	0.7	19.9	0.0	(0.0)	25.1	9.1
Cold Case	3.0	0.2	31.8	0.0	11.8	9.4

Exhibit 4-7 : Incremental Supply Costs (Million$) by year between the weather scenarios

Incremental supply costs (Million$)	2023	2024	2025	2026	2027	Annual Average
Normal Case	-	-	-	-	(15.8)	(3.2)
Warm Case	0.0	86.8	24.9	(211.6)	(4.7)	(20.9)
Typical Weather Case	95.8	(130.1)	(0.0)	0.0	(39.4)	(14.7)
Cold Case	(21.9)	30.6	(207.3)	-	(23.8)	(44.5)

Exhibit 4-8 : Incremental Transportation Costs (Million$) by year between the weather scenarios

Incremental transportation costs (Million$)	2023	2024	2025	2026	2027	Annual Average
Normal Case	-	-	-	-	3.3	0.7
Warm Case	(0.0)	0.0	2.1	1.2	0.6	0.8
Typical Weather Case	0.0	1.0	0.0	(0.0)	2.1	0.6
Cold Case	0.5	-	4.1	-	3.1	1.5

Exhibit 4-9 : Incremental Total Supply Portfolio Costs (Million$) by year between the weather scenarios

Incremental Total Supply Portfolio costs (Million$)	2023	2024	2025	2026	2027	Annual Average
Normal Case	(0.0)	0.0	(0.0)	(0.0)	(2.1)	(0.4)
Warm Case	0.0	87.8	54.9	(178.5)	(0.7)	(7.3)
Typical Weather Case	96.5	(109.3)	(0.0)	(0.0)	(12.1)	(4.9)
Cold Case	(18.4)	30.8	(171.5)	0.0	(8.9)	(33.6)

4.5 Impact of Different Weather Patterns on Storage Capacity

In all the scenarios, the increase in storage capacity allows Enbridge Gas to purchase additional lower cost natural gas supply during off-peak periods for use during the winter when prices typically are higher. Exhibit 4-10 illustrates the impact of the increase in storage capacity on Enbridge Gas supply portfolio costs for these scenarios. The change in costs from the existing base storage capacity case to the incremental storage capacity case is provided in Exhibit 4-9.

As outlined in Exhibit 4-5, the total supply portfolio costs in the Normal weather scenario with existing base storage capacity are about CAD$ 2.6 billion per year which remains almost the same in the incremental storage capacity cases.

In the months where incremental storage capacity is used by the Gas Supply Planning model, the total supply portfolio costs go down. Similarly, the total supply portfolio costs go up when no incremental storage is used by the model. This happens because the model must pay for unused storage for the months where it has contracted for storage but is not using the same.

In both the Warm Weather Case and the Cold Weather case, the analysis indicated that adding 30 PJ of storage capacity could be economic during certain periods. As outlined in Exhibit 1-3, in the Warm Weather case, the incremental storage capacity would reduce the supply portfolio cost by C$7.3 million per year, while in the Cold Weather case, the incremental storage capacity would reduce the supply portfolio cost by C$33.6 million per year.

Exhibit 4-10 : Average Annual Impact of Incremental Storage Capacity on Enbridge Gas Supply Portfolio Costs: Current Storage Capacity Costs (Million CAD$)

(CAD$Millions)	Normal (Base) Weather Scenario	Warmer than Normal Weather Scenario	Typical Weather Scenario	Colder than Normal Weather Scenario
Total Supply Portfolio Costs				
Aggregate Excess Capacity[21]	2,671	2,889	2,556	2,711
Incremental Storage Capacity[21]	2,671	2,882	2,551	2,677
Gas Supply Costs				
Aggregate Excess Capacity	2,049	2,263	1,934	2,092
Incremental Storage Capacity	2,046	2,242	1,919	2,048
Storage Costs				
Aggregate Excess Capacity	32	34	31	27
Incremental Storage Capacity	34	47	40	37
Transport Costs				
Aggregate Excess Capacity	590	592	591	591
Incremental Storage Capacity	591	592	592	593

In the Normal Weather scenario, the total supply portfolio costs in the incremental capacity case remains close to the Aggregate excess capacity case, implying that there is limited value in adding incremental storage capacity to the system. The calculation of normal weather significantly dampens the price volatility associated

[21] The difference between the ‘Aggregate Excess Capacity’ line and the “Incremental Storage Capacity’ line is the average annual cost savings, as outlined in Exhibit 4-9.

with normal variations in weather resulting in a lower value for storage, and when optimization modeling, the use of less storage capacity.

Impact of Incremental Fixed Storage Capacity on Supply Portfolio Costs

In the analysis of the value of incremental natural gas storage under alternative weather patterns, the Gas Supply Planning model adds storage capacity on a monthly basis in the months when it is less expensive and in turn saves on the total cost based on the market condition assumptions. In actual decision making there is no certainty on the requirement of storage in a particular month. Typically, storage customers would contract for storage capacity at least for a 12-month period, or longer, rather than only during the time periods when the storage reduces costs.[22]

ICF assumed that a fixed storage capacity will be contracted in each month and that the cost of the storage contract would be incurred over the entire analysis period. ICF added the incremental storage capacity costs to the Gas Supply Planning model results in order to provide a more realistic assessment of the total storage costs. ICF assumed fixed storage costs over the 5-year period, to understand how the cost savings will change with a long-term storage commitment in each of the weather scenarios.

Based on the outcome of the Resource Mix Optimization analysis as outlined in Exhibit 4-4 ICF assumed 10 PJ of fixed storage contracts in the Normal case, 25 PJ of fixed storage contracts in the Typical weather case, and 30 PJ of fixed storage capacity contracts in the Colder than normal and Warmer than normal weather scenarios, consistent with the maximum amount of gas storage selected for any period in the Gas Supply Planning model analysis. It was observed that the cost savings go down when the storage is fixed.

The overall results of the five-year period from April 2023 through March 2028 of weather and cost scenarios are shown in Exhibit 4-13.

The total supply portfolio costs go down (cost savings associated with fixed storage contracts) by CAD$ 0.1 million in a Normal Weather case when we assume fixed capacity contracts. The cost savings decrease in the alternative weather scenarios too, with cost savings ranging between CAD$ 1.5 million and CAD$ 9.7 million. Exhibit 4-11 shows the cost savings in each of the weather scenario by year when ICF assumed fixed storage contracts of 10 PJ in Normal weather case, 25 PJ in Typical weather case and 30 PJ each in Warm and Cold weather cases. The negative values indicate the cost reductions in the fixed storage contract case vs the Base case where no incremental storage was provided. These cost savings provide an indication of the potential cost savings associated with the use of incremental storage capacity based on storage behavior with perfect foresight.

[22] Storage customers can and do contract for short term storage to fill immediate needs.

Exhibit 4-11 : Incremental Total Supply Portfolio Costs in a fixed storage capacity scenario estimated by ICF

(CAD$Millions)	*2023*	2024	2025	2026	2027	Annual Average
Normal Weather	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Warm Weather	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
Typical Weather	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)
Cold Weather	(9.7)	(9.7)	(9.7)	(9.7)	(9.7)	(9.7)

Exhibit 4-12 below summarizes the annual average cost of incremental storage and the cost savings per PJ of storage addition in the incremental storage capacity case and the fixed storage capacity case.

Exhibit 4-12 : Annual Average Cost per PJ of storage addition and Cost savings per PJ of storage addition in the incremental storage capacity case and the fixed storage capacity case

CAD $ Millions/PJ	Normal Weather Scenario	Warmer than Normal Weather Scenario	Typical Weather Scenario	Colder than Normal Weather Scenario
Incremental Storage Capacity Case				
Annual average cost of incremental storage	0.99	1.05	1.02	0.98
Cost Savings	-0.04	-0.80	-1.24	-2.42
Fixed Storage Capacity Case				
Annual average cost of incremental storage with fixed contracts	0.05	0.14	0.11	0.09
Cost savings with fixed contracts	-0.01	-0.08	-0.06	-0.32

4.6 Impact of Incremental Fixed Storage Capacity on Supply Portfolio Costs

ICF also evaluated, for the "typical Weather" scenario, the impact on storage costs based on current storage operational guidelines with 1.2% maximum deliverability and 0.75% maximum injectability. For this analysis, ICF requested that Enbridge Gas use their gas supply planning model to evaluate the "Typical Weather" scenario using different levels of incremental storage capacity, including 5 PJ, 8 PJ, 10 PJ and 20 PJ above the level indicated by the aggregate excess methodology. This analysis calculates the cost of holding these different levels of incremental storage capacity over the 5-year period, as this more closely resembles how a utility would contract for and use storage capacity relative to the resource optimization analysis.

ICF based the Fixed Storage Capacity Analysis on the typical weather scenario rather than the Normal Weather scenario since the typical weather case is a better representation of how weather conditions impact price volatility and drive storage value.[23]

The results of the analysis are shown in Exhibit 4-13 and summarized in Exhibit 4-14. The analysis illustrates the impact of the adjustments for the value of deliverability based on the delivered services costs and the ability to minimize gas purchases during the highest price periods.

- Contribution of Storage Deliverability to Design Day Capacity Requirements. Storage deliverability provides a direct contribution to design day system capacity requirements. In the Gas Supply Planning model analysis, changes in storage capacity are addressed through incremental purchases at Dawn. However, purchases at Dawn do not have the degree of reliability provided by storage deliverability. The different in reliability provides significant economic benefit to the use of incremental storage that is not captured in the Gas Supply Planning model analysis.
- Contribution Value of Daily Gas Supply Purchasing Flexibility. Storage capacity allows for a more flexible gas purchasing approach that allows the utility to shift purchases on high priced days to purchases on lower priced days. This provides a direct economic benefit to the use of storage that is not captured in the use of storage to address aggregate excess requirements, or through the use of monthly average prices.

The estimated value of the increase in deliverability and the value that would be derived from the increase in daily gas supply purchasing flexibility are documented in Appendix E.

[23] Given the results of the Resource Mix Optimization analysis, it was clear that additional storage would provide additional benefits in the warm and cold weather scenarios, hence the additional analysis would not have provided sufficient value to justify the level of effort required and was not conducted,

Exhibit 4-13 : Impact of Different levels of Storage Capacity on the Total Supply Costs for the Typical Weather Scenario (Million$)

Total Supply Costs with Different Levels of Storage Capacity for the Typical Weather Scenario (Million$)					
	203 PJ	208 PJ	211 PJ	213 PJ	223 PJ
2023-24	2,991	2,920	2,924	2,926	2,936
2024-25	3,315	3,398	3,380	3,381	3,392
2025-26	2,432	2,445	2,455	2,459	2,471
2026-27	1,632	1,653	1,666	1,668	1,679
2027-28	2,385	2,380	2,370	2,363	2,330
2023-2028	12,755	12,796	12,795	12,797	12,808

Incremental Supply Costs with Different Levels of Storage Capacity for the Typical Weather Scenario (Million$)					
	203 PJ	208 PJ	211 PJ	213 PJ	223 PJ
2023-24	-	(70.8)	(67.0)	(65.0)	(54.9)
2024-25	-	83.0	65.5	66.2	77.9
2025-26	-	12.7	22.5	26.3	38.2
2026-27	-	20.8	33.7	35.8	46.4
2027-28	-	(4.8)	(14.9)	(21.7)	(55.0)
2023-2028	-	40.8	39.8	41.5	52.7
Percentage Change in Costs		0.320%	0.312%	0.326%	0.413%

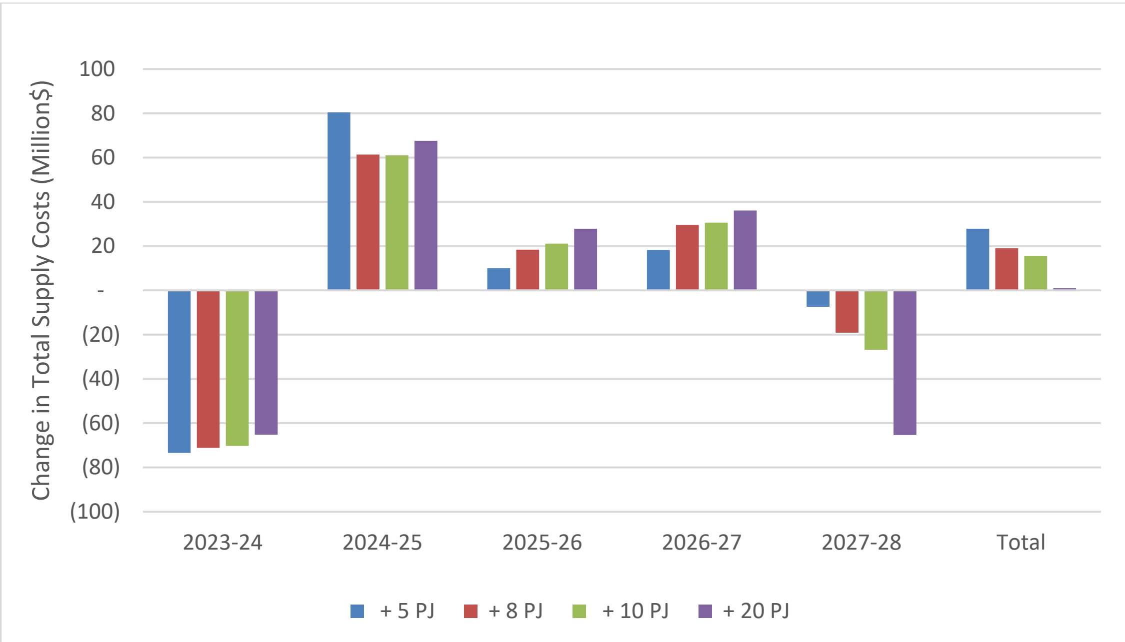
	203 PJ	208 PJ	211 PJ	213 PJ	223 PJ
Value of Incremental Deliverability	-	2.1	3.3	4.1	8.2
Reduction in Gas Purchase Costs	-	0.5	0.9	1.1	2.1

Total Supply Costs with Different Levels of Storage Capacity for the Typical Weather Scenario With Adjustment for Value of Incremental Deliverability (Million$)					
	203 PJ	208 PJ	211 PJ	213 PJ	223 PJ
2023-24	2,991	2,918	2,920	2,921	2,926
2024-25	3,315	3,395	3,376	3,376	3,382
2025-26	2,432	2,442	2,451	2,453	2,460
2026-27	1,632	1,651	1,662	1,663	1,668
2027-28	2,385	2,378	2,366	2,358	2,320
2023-2028	12,755	12,783	12,775	12,771	12,756

Incremental Supply Costs with Different Levels of Storage Capacity for the Typical Weather Scenario (Million$)					
	203 PJ	208 PJ	211 PJ	213 PJ	223 PJ
2023-24	-	(73.4)	(71.2)	(70.2)	(65.2)
2024-25	-	80.4	61.4	61.0	67.6
2025-26	-	10.1	18.4	21.1	27.9
2026-27	-	18.2	29.6	30.6	36.1
2027-28	-	(7.4)	(19.1)	(26.9)	(65.3)
2023-2028	-	27.9	19.1	15.7	1.0
Percentage Change in Costs		0.219%	0.150%	0.123%	0.008%

As indicated in Exhibit 4-14, in the typical weather scenario, additional storage capacity reduced overall costs in 2023/24 and in 2027/28, but resulted in an increase in costs in 2024/25, 2025/26, and 2026/27. Over the 5-year period, total costs were relatively flat across the range of incremental storage capacity. Costs changed by between 0.008% and 0.2% relative to the total supply portfolio cost depending on the amount of incremental storage capacity. This is in line with expectations given the price of storage capacity used in the analysis reflects actual storage contracts signed in the recent past, where we would anticipate that the storage cost reflects the value associated with the storage capacity.

Exhibit 4-14 : Impact of Incremental Storage Capacity on Supply Costs (Million$) in the Typical Weather Cases



Summary of Resource Mix Optimization and Fixed Storage Capacity Analysis

Exhibit 4-15 is a summary of the portfolio costs savings reflected in the analysis above, under both the Resource Mix Optimization analysis, and the Fixed Storage Capacity analysis. As outlined in Exhibit 4-15, total portfolio costs decrease in all scenarios evaluated.

Exhibit 4-15 : Average Annual Change in Total Gas Costs from Incremental Storage Capacity from Enbridge Gas SENDOUT© Results (Million CAD$)

Average Annual Impact of Incremental Storage Capacity on Enbridge Gas' Supply Portfolio Costs for the Five-Year Period from April 2023 to March 2028	
(CAD$Millions)	**Reference Storage Costs**
Normal Weather Scenario	
Aggregate Excess Storage Capacity	2671
Incremental Storage Capacity[24]	-0.4
Assuming Incremental Fixed Storage Capacity	-0.1
Warmer than Normal Weather Scenario	
Aggregate Excess Storage Capacity	2889
Incremental Storage Capacity	-7.3
Assuming Incremental Fixed Storage Capacity	-2.4
Typical Weather Scenario	
Aggregate Excess Storage Capacity	2556
Incremental Storage Capacity	-5.0
Assuming Incremental Fixed Storage Capacity	-1.5
Colder than Normal Weather Scenario	
Aggregate Excess Storage Capacity	2711
Incremental Storage Capacity	-33.6
Assuming Incremental Fixed Storage Capacity	-9.7

Based on the assessment of natural gas market trends, expected natural gas prices at Dawn, and the value of natural gas storage as part of the Enbridge Gas overall supply portfolio, ICF's analysis of natural gas markets in and around the Enbridge Gas distribution service territory, and Enbridge Gas' gas supply planning model analysis indicates that there is likely to be long term cost savings with holding additional storage capacity above the level indicated by the Aggregate Excess methodology for the use of in-franchise bundled customers. This analysis indicates that additional storage capacity that would be contracted at market-based rates would reduce the long-term average cost of gas for Enbridge Gas in-franchise customers. The cost savings range from $0.1 million per year in the Normal Weather case to $9.7 million per year in the Colder than Normal Weather scenario.

[24] The incremental storage capacity costs included in this table reflect Resource Mix Optimization cost, as outlined in Exhibit 1-3

5. Recommendations and Conclusions

Enbridge Gas estimated an aggregate excess storage capacity for bundled service customers of 203 PJ for the 2023-24 storage year. This value increases to 208 PJ by the 2027/28 storage year based on projected natural gas demand growth within this customer group. Given 185 PJ of utility owned storage capacity valued at the cost of service, this would require 18 PJ of market-based storage in 2023/24, increasing to 23 PJ of market-based storage in 2027/28.

Based on our assessment of storage economics and the value of storage in reducing customer cost volatility, ICF would consider the estimate of the Aggregate Excess to represent a lower bound on the appropriate level of storage capacity needed to serve in-franchise bundled service customers rather than the optimal amount. ICF's assessment of storage value under different weather conditions and time periods suggests that Enbridge Gas should hold a certain amount of additional market-based storage capacity above this level to meet design day system capacity requirements, to increase system reliability and reduce cost volatility to Enbridge Gas customers, and potentially to reduce overall costs to Enbridge Gas customers.

The overall amount of incremental capacity that should be considered by Enbridge Gas will depend on the cost of the incremental storage at the time that Enbridge Gas goes into the market to acquire the storage[25] and the level of importance Enbridge Gas, the OEB, and other stakeholders place on minimizing long term supply costs vs. the risk of holding additional storage capacity in years where the incremental value provided by the additional storage capacity does not exceed the cost.

ICF's analysis of the potential value of storage during unusual weather and market conditions indicates that up to 25 PJ of additional market-based storage capacity could provide value to Enbridge Gas bundled service customers in the "Typical Weather" Scenario, and up to 30 PJ of additional market-based storage capacity could provide value to Enbridge Gas bundled service customers in the Colder than Normal and Warmer than Normal weather scenarios. However, the incremental fixed cost of this additional storage capacity would lead to higher costs in many years and would require additional fixed cost commitments that reduce the attractiveness of holding additional storage capacity. In addition, fully achieving the benefits of the incremental storage capacity would require the ability to optimize gas supply purchase patterns.

Instead of the maximum amount of indicated storage capacity, ICF's analysis suggests that Enbridge Gas should consider increasing the amount of market-based storage capacity held for bundled service customers by about 10 PJ from 18 PJ to 28 PJ. This recommendation reflects a balance between cost, cost volatility, design day reliability, and minimizing up front contract cost commitments for supply services based on the results of the assessment of the value of storage under different weather conditions, and the assessment of the impacts of different levels of storage capacity on costs for the typical weather scenario. The recommendation is based on both the analysis of alternative weather scenarios, and the analysis of alternative storage capacity levels for the "Typical Weather" scenario. Overall, supply costs for bundled in-franchise customers remained relatively flat across a range of storage capacity options. The supply portfolio costs changed by between 0.008% and 0.2%

[25] Given expectations about changes in the future seasonal value of natural gas, long term storage costs are expected to be lower in the next two years than thereafter, providing incentives to lock in longer term storage capacity in the near term.

relative to the total supply portfolio cost depending on the amount of incremental storage capacity provided in the typical weather case. The values increased in the Colder than Normal and Warmer than Normal scenarios, with the Colder than Normal scenario yielding a larger return of close to $9.7 million per year.

In the analysis of alternative weather scenarios, ICF's recommendation is generally consistent with the annual average of incremental storage capacity over the five-year period for the Typical Weather Scenario between 2023 and 2028, which 44.4 PJ in total over the five-year period, or about 10 PJ per year, as well as the Warm Weather Scenario and Cold Weather Scenario, which averaged 10.5 PJ per year.

The analysis of incremental storage value for the Typical Weather scenario indicated that increasing the incremental storage capacity above the level indicated by the Aggregate Excess by between 5 and 20 PJ of capacity would reduce gas supply costs during the first year of the analysis (Storage year 2023/24) and would have essentially no impact on costs over the five-year period from 2023 through 2028. In addition, the incremental storage capacity would increase system reliability and resiliency and is expected to lead to additional cost savings due to the flexibility in gas purchase timing facilitated by the incremental storage capacity. However, the cost savings resulting from going from 10 PJ of incremental storage to 20 PJ of incremental storage are small and may not offset the impact of the commitment for additional storage capacity.

Hence, based on the analysis of both the potential value of storage under different weather conditions, and the value of incremental storage capacity in the "Typical Weather" scenario, ICF recommends the 10 PJ of incremental storage capacity as the best balance between the projected value of the incremental storage capacity to minimize gas supply costs, the value of reducing gas cost uncertainty and volatility, and the reliability benefits provided by storage capacity, and the fixed cost commitments needed to contract for the storage capacity.

Appendix A: Natural Gas Prices at Dawn for the Four Alternative Weather Scenarios

Exhibit A 1: Natural Gas Prices at Dawn for the Four Enbridge Gas Weather Scenarios

Prices at Dawn - Nom US$/MMBtu	Normal Case	Warm Case	Typical Case	Cold Case
2023 Summer	4.3	4.1	3.9	4.2
2023/24 Winter	4.2	3.3	3.6	4.8
2024 Summer	3.3	3.7	4.7	4.4
2024/25 Winter	3.3	3.2	4.7	3.6
2025 Summer	3.0	2.1	3.4	2.2
2025/26 Winter	3.1	2.5	2.7	4.9
2026 Summer	3.0	5.5	2.0	3.2
2026/27 Winter	3.5	5.7	1.6	4.0
2027 Summer	2.8	3.4	2.9	1.4
2027/28 Winter	3.7	3.8	3.5	2.6
2028 Summer	2.8	3.5	3.2	2.7

Source: ICF GMM®

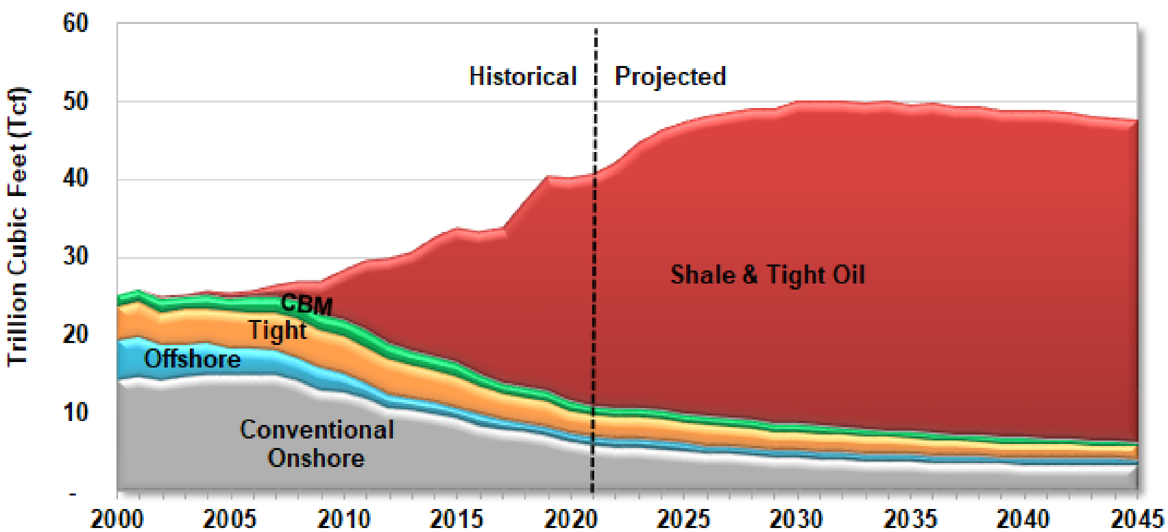
Appendix B: Assumptions behind ICF's Natural gas Market Outlook – April 2022

This section discusses U.S. and Canadian Base Case natural gas market forecasts, starting with natural gas supply trends, including ICF's resource base assessment and comparisons with other assessments. The section then discusses trends in U.S. and Canadian demand through 2045, including pipeline construction and LNG export trends. The section concludes with forecasts on U.S. and Canadian natural gas pipeline and international trade and natural gas prices.

U.S. and Canadian Natural Gas Supply Trends

Over the past several years, natural gas production in the U.S. and Canada has grown quickly, led by unconventional production. Production is expected to grow further through 2030 and then expected to remain flat (see Exhibit B 1). Recent unconventional production technology advances (i.e., horizontal drilling and multi-stage hydraulic fracturing) have fundamentally changed supply and demand dynamics for the U.S. and Canada, with unconventional natural gas and tight oil production expected to far exceed declining conventional production. These production changes have incentivized significant infrastructure investments to create pathways between new supply sources and demand markets.

Exhibit B 1 : U.S. and Canadian Gas Supplies



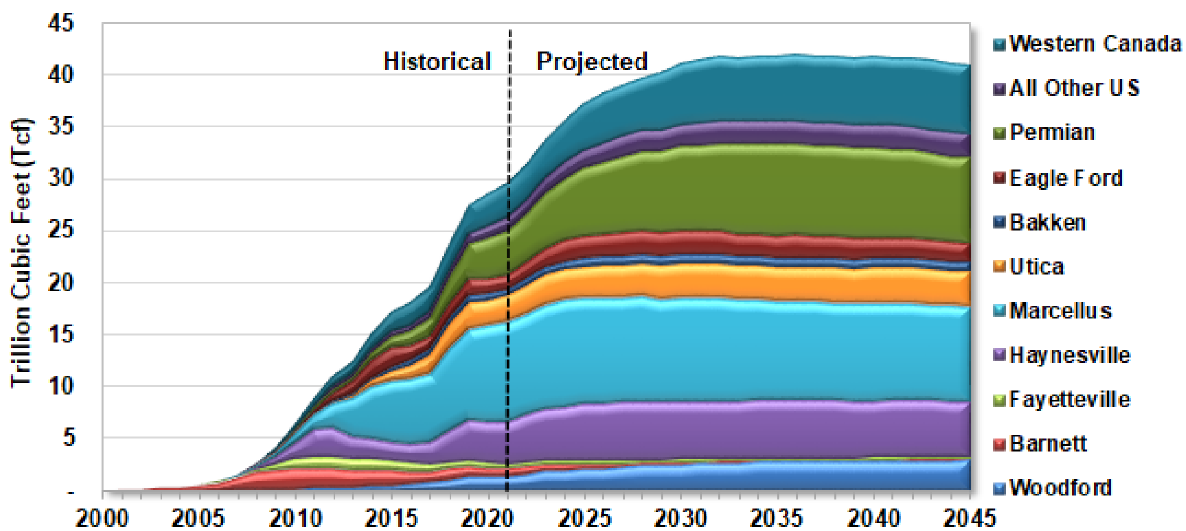
Source: ICF GMM® Q2 2022

Production from U.S. and Canadian shale formations will grow from 31.4 Tcf per year (86.1 Bcfd) in 2022 or 75 percent of total production to 41.1 Tcf per year (112.5 Bcfd) by 2045 or 87 percent of total production (see exhibit above). The projection assumes West Texas Intermediate (WTI) crude price of $70/Bbl ($2021).

The major shale formations in the U.S. and Canada are in the U.S. Northeast (Marcellus and Utica), the Mid-continent and North Gulf States (Woodford, Fayetteville, Barnett, and Haynesville), South Texas (Eagle Ford), and western Canada (Montney and Horn River). The Permian, Niobrara, and Bakken are primarily producing oil with associated natural gas volumes. Associated gas production from the Permian, Niobrara, and Bakken is expected to grow significantly in the next 10 years. Dry gas[26] production from the lower cost Permian basin will reach 8.2 Tcf per year (22.6 Bcfd) by 2045, mostly gas associated with tight oil, from about 4.7 Tcf (12.8 Bcfd) in 2022.

ICF did not include in our forecast potential shale and tight oil formations in the U.S. and Canada that have not yet been evaluated or developed for gas and oil production.

Exhibit B 2 : U.S. and Canadian Shale Gas Production



Source: ICF GMM® Q2 2022

Natural Gas Production Costs

ICF estimates that production of unconventional natural gas (including shale gas, tight gas, and coalbed methane (CBM) will generally have much lower cost on a per-unit basis than conventional sources.[27] The gas supply curves show the incremental cost of developing different types of gas resources, as well as for the resource base in total. Even though their production costs are uncertain due the newness of the plays and considerable site-to-site variation in geology, shale plays such as the Marcellus and Permian and other tight oil plays are proving to be among the least expensive (on a per-unit basis) natural gas sources.

ICF has developed resource cost curves for the U.S. and Canada. These curves represent the aggregation of discounted cash flow analyses at a highly granular level. Resources included in the cost curves are all the resources discussed above – proven reserves, growth, new fields, and unconventional gas. The detailed unconventional geographic information system (GIS) plays are represented in the curves by thousands of individual discounted cash flow (DCF) analyses.

Conventional and unconventional gas resources are determined using different approaches due to the nature of each resource. For example, conventional new fields require new field wildcat exploration while shale gas and tight oil are almost all development drilling. Offshore undiscovered conventional resources require special analysis related to production facilities as a function of field size and water depth.

The basic ICF resource costs are determined first “at the wellhead” prior to gathering, processing, and

[26] Dry gas is natural gas which remains after processing plant separation, also known as consumer-grade natural gas.

[27] Unconventional refers to production that requires some form of stimulation (such as hydraulic fracturing) within the well to produce gas economically. Conventional wells do not require stimulation.

transportation. Then, those cost factors are added to estimate costs at points farther downstream of the wellhead. Costs can be further adjusted to a "Henry Hub" basis by adding regional basis differentials for certain type of analysis that considers the locations of resources relative to markets.

Supply Costs of Conventional Oil and Gas

Conventional undiscovered fields are represented by a field size distribution. Such distributions are typically compiled at the "play" level. Typically, there are a few large fields and many small fields remaining in a play. In the model, these play-level distributions are aggregated into 5,000-foot drilling depth intervals onshore and by water depth intervals offshore. Fields are evaluated in terms of barrels of oil equivalent, but the hydrocarbon breakout of crude oil, associated gas, non-associated gas, and gas liquids is also determined. All areas of the Lower-48, Canada, and Alaska are evaluated.

Costs involved in discovering and developing new conventional oil and gas fields include the cost of seismic exploration, new field wildcat drilling, delineation and development drilling, and the cost of offshore production facilities. The model includes algorithms to estimate the cost of exploration in terms of the number and size of discoveries that would be expected from an increment of new field wildcat drilling.

Supply Costs of Unconventional Oil and Gas

ICF has developed models to assess the technical and economic recovery from shale gas and other types of unconventional gas plays. These models were developed during a large-scale study of North America gas resources conducted for a group of gas-producing companies and have been subsequently refined and expanded. North American plays include all the major shale gas plays that are currently active. Each play was gridded into 36 square mile units of analysis. For example, the Marcellus Shale play contains approximately 1,100 such units covering a surface area of almost 40,000 square miles.

The resource assessment is based upon volumetric methods combined with geologic factors such as organic richness and thermal maturity. An engineering-based model is used to simulate the production from typical wells within an analytic cell. This model is calibrated using actual historical well recovery and production profiles.

The wellhead resource cost for each 36-square-mile cell is the total required wellhead price in dollars per MMBtu needed for capital expenditures, cost of capital, operating costs, royalties, severance taxes, and income taxes.

Wellhead economics are based upon discounted cash flow analysis for a typical well that is used to characterize each cell. Costs include drilling and completion, operating, geological and geophysical (G&G), and lease costs. Completion costs include hydraulic fracturing, and such costs are based upon cost per stage and number of stages. Per-foot drilling costs were based upon analysis of industry and published data. The American Petroleum Institute (API) Joint Association Survey of Drilling Costs and Petroleum Services Association of Canada (PSAC) are sources of drilling and completion cost data, and the U.S. Energy Information Administration (EIA) is a source for operating and equipment costs.28,29,30 Lateral length, number of fracturing stages, and cost per fracturing stage assumptions were based upon commercial well databases, producer surveys, investor slides, and other sources.

In developing the aggregate North American supply curve, the play supply curves were adjusted to a Henry Hub, Louisiana basis by adding or subtracting an estimated differential to Henry Hub. This has the effect of adding costs to more remote plays and subtracting costs from plays closer to demand markets than Henry Hub.

The cost of supply curves developed for each play include the cost of supply for each development well spacing. Thus, there may be one curve for an initial 120-acre-per-well development, and one for a 60-acre-per-well option.

[28] American Petroleum Institute. "Joint Association Survey of Drilling Costs". API, 2012 and various other years: Washington, DC.

[29] Petroleum Services Association of Canada (PSAC). "Well Cost Study". PSAC, 2009 and various other years. Available at: http://www.psac.ca/

[30] U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs". EIA, 2011 and various other years: Washington, DC. Available at: http://www.eia.gov/petroleum/reports.cfm

This approach was used because the amount of assessed recoverable and economic resource is a function of well spacing. In some plays, down spacing may be economic at a relatively low wellhead price, while in other plays, economics may dictate that the play would likely not be developed on closer spacing. The factors that determine the economics of infill development are complex because of varying geology and engineering characteristics and the cost of drilling and operating the wells.

The initial resource assessment is based on current practices and costs and, therefore, does not include the potential for either upstream technology advances or drilling and completion cost reductions in the future. Throughout the history of the gas industry, technology improvements have resulted in increased recovery and improved economics. In ICF's oil and gas drilling activity and production forecasting, assumptions are typically made that well recovery improvements and drilling cost reductions will continue in the future and will have the effect of reducing supply costs. Thus, the current study anticipates there will be more resources available in the future than indicated by a static supply curve based on current technology.

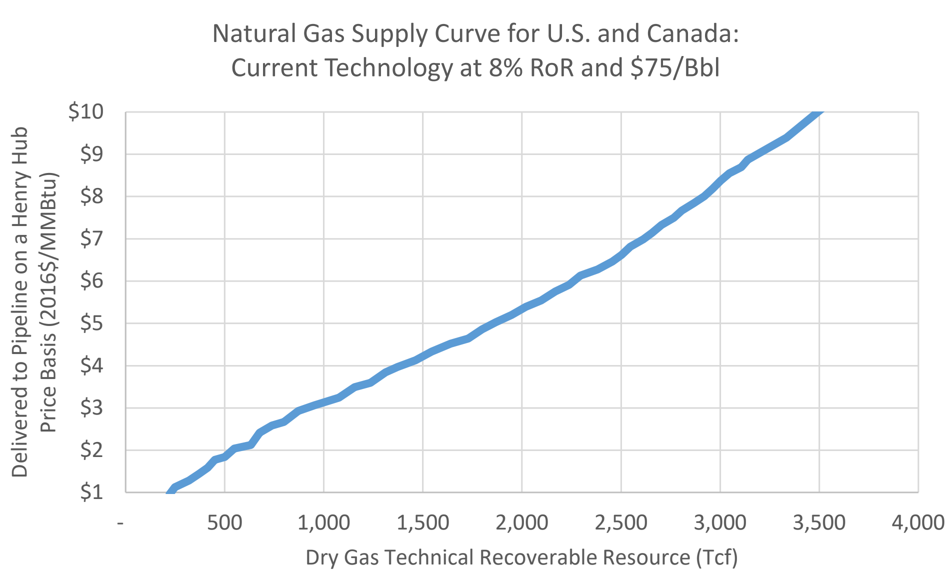
Aggregate Cost of Supply Curves

U.S. and Canadian supply cost curves (based on current technology) on a "Henry Hub" price basis are presented in Exhibit B 3. The supply curves were developed on an "oil-derived" basis. That is to say, the liquids prices are fixed in the model (crude oil at $75 per barrel) and the gas prices in the curve represent the revenue that is needed to cover those costs that were not covered by the liquids in the DCF analysis. The rate of return criterion is 8 percent, in real terms. Current technology is assumed in terms of well productivity, success rates, and drilling costs.

A total of about 1,200 to 1,400 Tcf of gas resource in the U.S. and Canada is available at gas prices between $3.50 and $4.00 per MMBtu.

This analysis shows that a large component of the technically recoverable resource is economic at relatively low wellhead prices. This supply curve assessment is conservative in that it assumes no improvement in drilling and completion technology and cost reduction, while in fact, large improvements in these areas have been made historically and are expected in the future.

Exhibit B 3 : U.S. and Canada Natural Gas Supply Curves

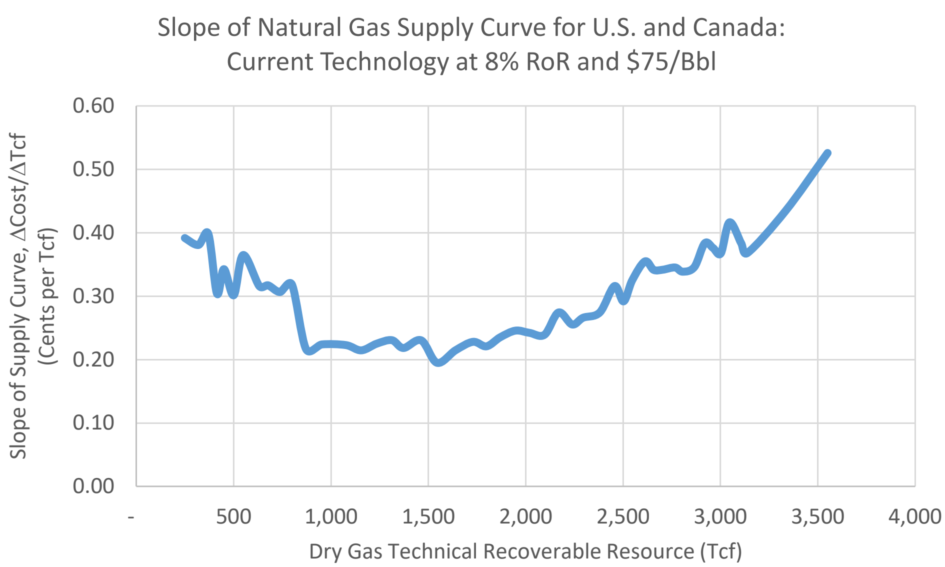


Source: ICF

A natural gas supply curve can also be described in terms of its slope.

Exhibit B 4 shows the slope of the Lower 48 plus Canada curve in cents per Tcf. In the forecast cases to be shown later in this report, the U.S. is projected to develop approximately 847 to 945 Tcf of natural gas resources through 2040 and Canada to develop another 166 to 176 Tcf. Combining the two countries, depletion for the U.S. and Canada will be in the range of 1,013 to 1,121 Tcf. This means that incremental development of one Tcf of natural through 2040 would have a “depletion effect on price” of natural gas of 0.2 to 0.4 cents (assuming no upstream technological advances to increase available volumes and to decrease costs) during the forecast period. As is explained below, the depletion effect on price is only one of several factors that need to be considered when estimating the price impacts of LNG exports or any other change to demand.

Exhibit B 4 : Slope of U.S. and Canada Natural Gas Supply Curve



Source: ICF

Representation of Future Upstream Technology Improvements

Technological advances have played a big role in increasing the natural gas resource base in the last few years and in reducing its costs. As discussed below, it is reasonable to expect that similar kinds of upstream technology improvements will occur in the future and that those advances will make more low-cost natural gas available than what is indicated by the “current technology” gas supply curves.31

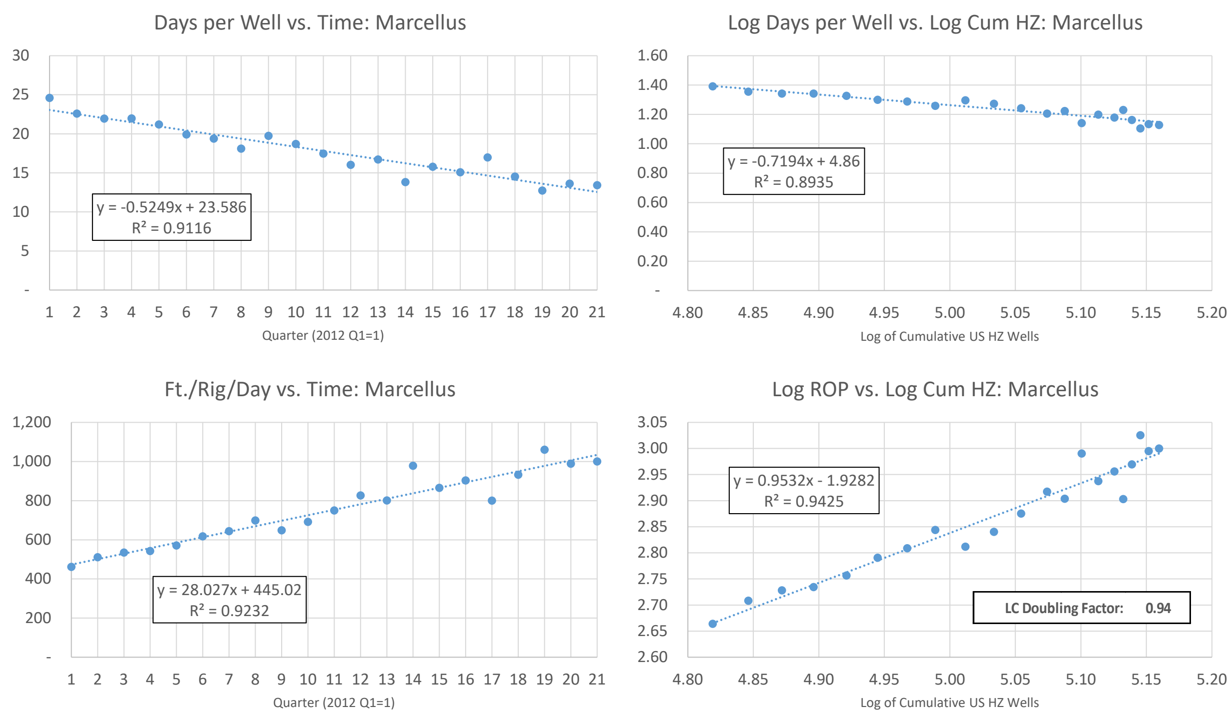
Technology advances in natural gas development in recent years have been related to the drilling of longer horizontal laterals, expanding the number and effectiveness of stimulation stages, use of advanced proppants and fluids, and the customization of fracture treatments based upon real-time micro-seismic and other monitoring. Lateral lengths and the number of stimulation stages are increasing in most plays and the amount of proppant used in each stimulation has generally gone up. These changes to well designs can increase the cost per well over prior configurations. The percentage increase in gas and liquids recovery is much greater than the percentage increase in cost, however, resulting in lower costs per unit of reserve additions.

[31] This discussion of upstream technology effects has been adapted from prior report written by ICF including “Impact of LNG Exports on the U.S. Economy: A Brief Update,” Prepared for API, September 2017. See http://www.api.org/news-policy-and-issues/lng-exports/impact-of-lng-exports-on-the-us-economy

Technology Advances in Rig Efficiency

ICF expects that drilling costs (as measured in real dollars per foot of measured well depth) will continue to be reduced largely due to increased efficiency and the higher rate of penetration (feet drilled per rig per day). ICF's modeling of drilling activity and costs considers how changes in oil and gas prices and activity levels can influence the unit cost of drilling, stimulation (hydraulic fracturing) services and other equipment and oil field services used to develop oil and gas. Thus, higher oil and gas prices translate into higher factor costs, which partially dampens the ability of higher commodity prices to lead to increase drilling activity and more production. As illustrated in the upper-left-hand chart in Exhibit B 5, the number of rig days required to drill a well has fallen steadily in many plays. This chart shows that Marcellus gas shale wells drilled in early 2012 required 24.6 rig days but that by early 2017 that had fallen to 13.4 days. Because lateral lengths increased over this time, total footage per well was going up (from 11,300 to 13,400 feet for Marcellus wells) over this period. As shown in the lower-left-hand chart in Exhibit B 5 this meant that footage drilled per rig per day (RoP) was going up quickly. For the Marcellus play RoP went from 461 feet in per day early 2012 to 1,000 feet per day in early 2017. Rig day rates and other service industry costs have declined since 2013 due to reduced drilling activity brought on by lower oil and gas prices and lack of demand for rigs. Improved technology and efficiency in combination with lower rig rates and other service costs have allowed industry to develop economic resources despite low oil and gas prices.

Exhibit B 5 : Recent Trends in Rig-Days Required to Drill a Well: Marcellus Shale (first quarter 2012 to first quarter 2017)



Source: ICF

To estimate the contributions of changing technologies ICF employs the "learning curve" concept used in several industries. The "learning curve" describes the aggregate influence of learning and new technologies as having a certain percent effect on a key productivity measure (for example cost per unit of output or feet drilled per rig per day) for each doubling of cumulative output volume or other measure of industry/technology maturity. The learning curve shows that advances are rapid (measured as percent improvement per period-of-time) in the early stages when industries or technologies are immature and that those advances decline through time as the industry or technology matures.

The two right-hand charts in Exhibit B 5 show how learning curves for rig efficiency can be estimated. The horizontal axis of both charts is the base 10 log of the cumulative number of horizontal multi-stage hydraulically fractured wells drilled in the U.S. and Canada. The y-axis of the upper-right-hand chart is the base 10 log of the rig days needed per well. The y-axis of the lower-right-hand chart is the base 10 log of RoP measured in feet per day per rig. The log-log least-square regression coefficients need to be converted[32] to get the learning curve doubling factor of -0.39 for rig days per well and 0.94 for RoP. What this mean is that rig days per well go down by 39% for each doubling of cumulative horizontal multi-stage hydraulically fractured wells and that RoP goes up by 94% for each doubling.

The rig efficiency learning curve factors shown for the Marcellus are some of the largest among North American gas shale and tight oil plays. The average learning curve doubling factor for rig efficiency among all horizontal multi-stage hydraulically fractured plays is -0.13 when measured as rig days per well and 0.44 when measured as RoP.

Technology Advances in EUR per Well or EUR per 1,000 feet of Lateral

ICF also used the learning curve concept to analyze trends in estimated ultimate recovery (EUR) per well over time to determine how well recoveries are affected by well design and other technology factors and how average EURs are affected by changes in mix of well locations within a play. The most technologically immature resources, wherein technological advances are among the fastest, include gas shales and tight oil developed using horizontal multi-stage hydraulically fractured wells. As with the rig efficiency calculations shown above, when looking at EURs for horizontal gas shale or tight oil wells, ICF estimates what the percent change in EUR is for each doubling of the cumulative North American horizontal multi-stage fracked wells. We first measure EUR on a per-well basis to look at total effects and then EUR per 1,000 feet of lateral to separate out the effect of increasing lateral length. This statistical analysis is done using a "stacked regression" wherein each geographic part of the play is treated separately to determine the regression intercepts, but all areas are looked at together to estimate a single regression coefficient (representing technological improvements) for the play.

We find that the total technology learning curve shows roughly 30 percent improvement in EUR per well for each doubling of cumulative horizontal multistage fracked wells. When we take out the effect of lateral lengths by fitting EUR per 1,000 feet of lateral rather than EUR per well, we find the learning curve effect is roughly 20 percent per doubling of cumulative wells. In other words, about one-third of the observed total 30% improvement in EUR per well doubling factor is due to increase lateral lengths and about two-thirds are due to other technologies such as better selection of well locations, denser spacing of frack stages, improved fracture materials and designs, and so on.

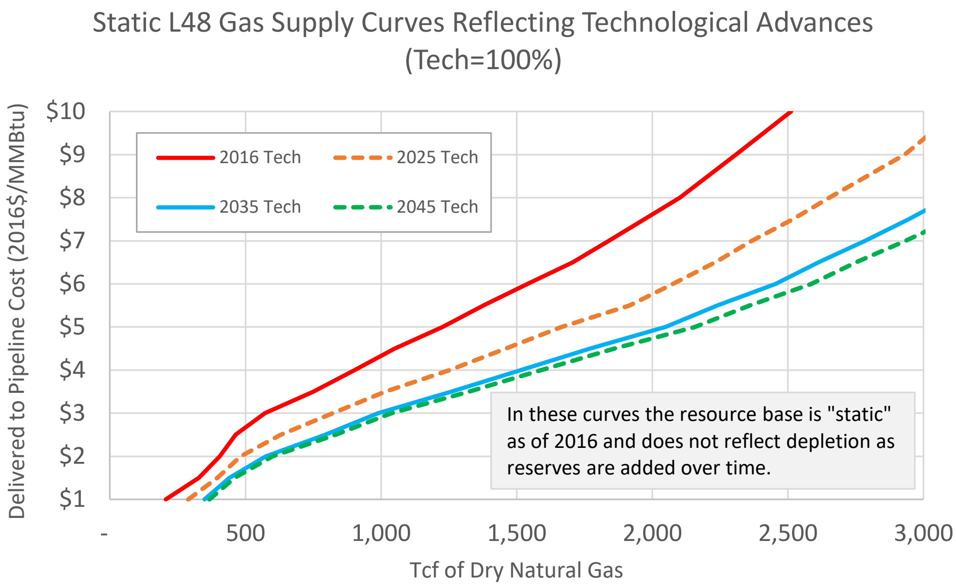
The Effect of Technology Advances on the Gas Supply Curves

The net effect of assuming that these technology trends continue in the future is to increase the amount of natural gas that is available at any given price. In other words, the gas supply curve "shifts down and to the right." This effect is illustrated in Exhibit B 6 which shows the Lower 48 natural gas supply curve for 2016 technology as a red line. The other lines in the chart represent the same (undepleted) resource that existed as of the beginning of 2016 but as it could be developed under the improved technologies assumed to exist in 2025 (dashed orange line), 2035 (blue line) and 2045 (dashed green line). ICF estimates that by extrapolating recent technological advances into the future, the amount of gas in the Lower 48 that are economic at $5/MMBtu would

[32] Doubling factor = $2^{C}-1$ where C is the regression slope coefficient.

increase from 1,225 Tcf to 2,160 Tcf, a 76% increase. The improved technologies include for gas shales and tight oil the EUR and rig efficiency improvements discussed above. Conventional resources and coalbed methane are assumed to be much more mature technologies with little future improvement (on average one-half of percent per year net reduction in cost per unit of production)

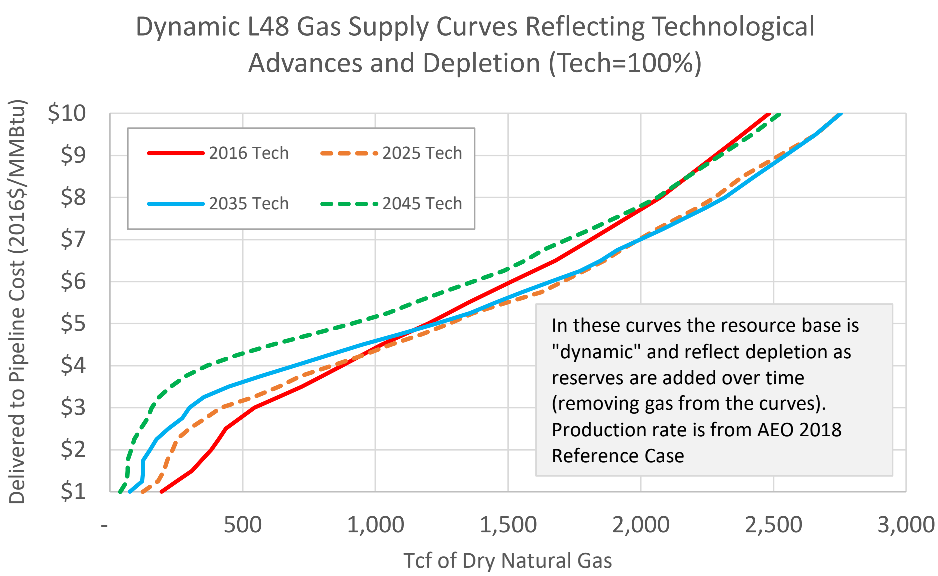
Exhibit B 6 : Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (static curves representing undepleted resource base as of 2016)



Source: ICF

The effect of technology advances on gas supply curves are shown in another way in Exhibit B 7. Here the Lower 48 curves are adjusted over time to show the effects of depletion based on reserve additions that would be expected to occur under the 2018 AEO Reference Case (that is for instance, cumulative reserve additions of 974 Tcf by 2040). In Exhibit B 7 the dashed orange line, for example, is the supply curve that would exist in the year 2025 if reserve additions consistent with the 2018 AEO Reference Case production forecast were to occur between now and then and that the technology advances assumed by ICF were to take place through 2025. Since technology adds resources faster than production takes place (consistent with the recent assessments made by ICF, Potential Gas Committee (PGC) and EIA), the upper part of the curve moves to the right from 2016 to 2025 and again from 2025 to 2035. However, because the technology advances for unconventional gas resource are represented by learning curves that flatten out over time, the upper part of the curve for 2045 moves to the left relative to the 2035 curve. Another important observation from these curves is that the lower-cost parts of the supply curve deplete more quickly than the high-cost portions as producers concentrate on low-cost (high profit) segments and will not exploit resources that have costs higher than prevailing market prices. Even so, the amount of natural gas available in these curves at $5.00 per MMBtu increases through 2035 and even by 2045 the curve still has approximately 1,000 Tcf at that price.

Exhibit B 7 : Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (dynamic curves showing effects of depletion through time)



Source: ICF

The development of supply curves and the projection of how those curves will change through time is inherently uncertain given that:

- Our understanding of the geology of the natural gas and tight oil resource base changes as known plays are developed, their geographic boundaries are expanded, and new plays are discovered and enter development,
- The technologies used to develop those resources evolve, thus, improving their performance and changing the unit cost of equipment and services employed in oil and gas development,
- The market for energy evolves, thus, changing the volumes produced and prices of natural gas and competing fossil and renewable resources.

This means that the estimates provided here for the market impacts of any given amount of LNG exports could be proven in time to be overstated or understated. In reviewing the trends of economic impact studies performed over the last serval years with regard to U.S. LNG exports, we see that the more recent studies show lower impacts in terms of cents per MMBtu of natural gas price increases per 1 Bcfd of exports compared to the older studies. This indicates that the forecasts have tended to:

- Understate natural gas supply robustness (that is, upstream technologies have evolved faster than expected and reduced the cost of developing natural gas more than expected) and
- Understate energy market forces that have reduced the domestic needs for natural gas (e.g., slower overall growth in demand for all energy and higher market penetration of renewables).

If these apparent forecasting biases still exists, then the price impacts for a given volume of LNG exports shown in this and similar economic impact reports will turn out lower.

ICF Resource Base Estimates

ICF has assessed conventional and unconventional North American oil and gas resources and resource economics. ICF's analysis is bolstered by the extensive work we have done to evaluate shale gas, tight gas, and coalbed methane in the U.S. and Canada using engineering and geology-based geographic information system

(GIS) approaches. This highly granular modeling includes the analysis of all known major North American unconventional gas plays and the active tight oil plays. Resource assessments are derived either from credible public sources or are generated in-house using ICF's GIS-based models.

The following resource categories have been evaluated:

Proven reserves – defined as the quantities of oil and gas that are expected to be recoverable from the developed portions of known reservoirs under existing economic and operating conditions and with existing technology.

Reserve appreciation – defined as the quantities of oil and gas that are expected to be proven in the future through additional drilling in existing conventional fields. ICF's approach to assessing reserve appreciation has been documented in a report for the National Petroleum Council.[33]

Enhanced oil recovery (EOR) – defined as the remaining recoverable oil volumes related to tertiary oil recovery operations, primarily CO_2 EOR**.**

New fields or undiscovered conventional fields – defined as future new conventional field discoveries. Conventional fields are those with higher permeability reservoirs, typically with distinct oil, gas, and water contacts. Undiscovered conventional fields are assessed by drilling depth interval, water depth, and field size class.

Shale gas and tight oil – **Shale gas** volumes are recoverable volumes from unconventional gas-prone shale reservoir plays in which the source and reservoir are the same (self-sourced) and are developed through hydraulic fracturing. **Tight oil** plays are shale, tight carbonate, or tight sandstone plays that are dominated by oil and associated gas and are developed by hydraulic fracturing.

Tight gas sand – defined as the remaining recoverable volumes of gas and condensate from future development of very low-permeability sandstones.

Coalbed methane – defined as the remaining recoverable volumes of gas from the development of coal seams. Exhibit B 8 summarizes the current ICF gas and crude oil assessments for the U.S. and Canada.

Resources shown are "technically recoverable resources." This is defined as the volume of oil or gas that could technically be recovered through vertical or horizontal wells under existing technology and stated well spacing assumptions without regard to price using current technology. The current assessment temporal basis is the start of 2016. The current assessment is 3,693 Tcf. As shown in the exhibit below, almost 65 percent of the gas resources is from shale gas and tight oil plays. Large portion of the resources is in the Marcellus, Utica, and Haynesville shale gas plays. The largest tight oil gas resource is in the Permian basin. It accounts for almost 30% of the gas resource from tight oil plays.

[33] This methodology for estimating growth in old fields was first performed as part of the 2003 NPC study of natural gas and has been updated several times since then. For details of methodology see U.S. National Petroleum Council, 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," http://www.npc.org/

Exhibit B 8 : ICF North America Technically Recoverable Oil and Gas Resource Base Assessment (current technology)

(Tcf of Dry Total Gas and Billion Barrels of Liquids as of 2016; Excludes Canadian and U.S. Oil Sands)

	Total Gas	Crude and Cond.
Lower 48	**Tcf**	**Bn. Bbls**
Proved reserves	320	33
Reserve appreciation and low Btu	161	17
Stranded frontier	0	0
Enhanced oil recovery	0	42
New fields	361	71
Shale gas and condensate	2,133	86
Tight oil	252	78
Tight gas	401	7
Coalbed methane	65	0
Lower 48 Total	**3,693**	**334**
Canada		
Proved reserves	71	5
Reserve appreciation and low Btu	23	3
Stranded frontier	40	0
Enhanced oil recovery	0	3
New fields	205	12
Shale gas and condensate	618	14
Tight oil	26	10
Tight gas (with conventional)	0	0
Coalbed methane	75	0
Canada Total	**1,058**	**46**
Lower-48 and Canada Total	**5,751**	**380**

Sources: ICF, EIA (proved reserves)

Resource Base Estimate Comparisons

The ICF natural gas resource base assessment for the U.S. Lower 48 states is historically higher than many other sources, primarily due to our bottom-up assessment approach and the inclusion of resource categories (including infill wells) that are excluded in other analyses. These additional resources in the ICF assessments tend to be in the lower-quality fringes of currently active play areas or are associated with lower-productivity infill wells that may eventually be drilled between current adjacent well locations. Therefore, the additional resources are often higher cost and are added to the upper end of the natural gas supply curves. Such resources may eventually be exploited if natural gas prices increase substantially or if upstream technological advances improve well recovery and decrease costs enough to make these resources economic. The inclusion of these fringe and infill resources into the ICF forecasts has little effect on results in the near term because current drilling and the drilling forecast for the next 20 years will be in the "core" and "near-core" areas. Therefore, removing the fringe/infill resources will not have a great effect on model runs projecting market results through 2045.

There are several other reasons for the magnitude of the differences:

- More plays are included. ICF includes all major shale plays that have significant activity. Although in recent years, EIA has published resources for most major plays, the ICF analysis is more complete. Examples of plays assessed by ICF but not by EIA are the Paradox Basin shales and Gulf Coast Bossier. ICF also has a more comprehensive evaluation of tight oil and associated gas.

- ICF includes the entire shale play, including the oil portion. Several plays such as the Eagle Ford have large liquids areas.
- ICF employs a bottom-up engineering evaluation of gas-in-place (GIP) and original oil-in-place (OOIP). Assessments based upon in-place resources are more comprehensive.
- ICF looks at infill drilling (or new technologies that can substitute for infill wells) that increase the volume of reservoir contacted. Infill drilling impacts are critical when evaluating unconventional gas. ICF shale resources are based upon the first level of infill drilling, with primary spacing based upon current practices. In other words, if the current practice is 120 acres and 1,000 feet spacing between horizontal well laterals, our assessment assumes an ultimate spacing can be (if justified by economics) 60 acres and 500 feet spacing between laterals.
- For conventional new fields, ICF includes areas of the Outer Continental Shelf (OCS) that are currently off-limits, such as the Atlantic and Pacific OCS.
- ICF evaluates all hydrocarbons at the same time (i.e., dry gas, NGLs, and crude and condensate). While not affecting gas volumes, it provides a comprehensive assessment.
- ICF employs an explicit risking algorithm based upon the proximity to nearby production and factors such as thermal maturity or thickness.

It should also be noted that ICF volumes of technically recoverable resources include large volumes of currently uneconomic resources on the fringes of the major plays, although ICF did not include shale gas reservoirs with a net thickness of less than 50 feet.

ICF has evaluated the United States Geological Survey (USGS) Marcellus shale gas assessment to determine the factors that contribute to their low assessment. We concluded that USGS used incorrect well recovery assumptions that are far lower than what is currently being seen in the play. In addition, the well spacing assumptions differ from current practices. EIA is using a modified version of the USGS Marcellus that is still low compared to ICF evaluation. The relatively high ICF Barnett Shale assessment is the result of our including a large fringe area of low-quality resource. The great majority of this fringe area is uneconomic, so the comparison is not for an equivalent play area.

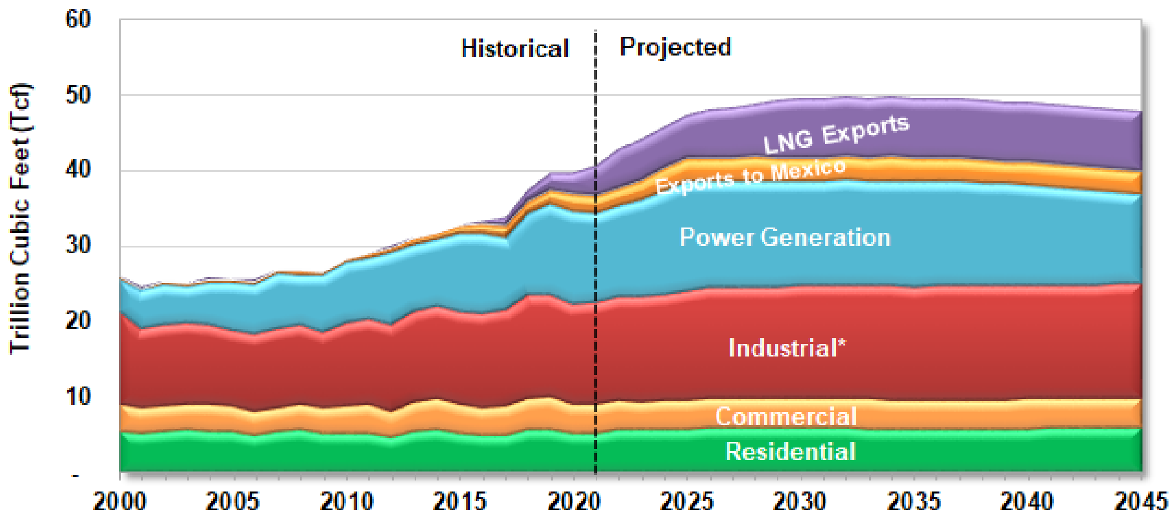
The ICF assessment of tight oil associated gas is much higher than that of other assessments. The difference reflects our inclusion of more plays and entire play areas. It also reflects our methodology, which generally assesses recoverable resources through determination of resource in-place, with an assumed recovery factor that is calibrated to existing well recoveries. Our assessment of several plays in Oklahoma is also based upon a new data-intensive method using GIS and well level recovery estimates, and that method typically results in higher assessments.

U.S. and Canadian Natural Gas Demand Trends

Natural gas exports (LNG and Mexico) are key drivers for near-term and long-term demand growth and account for about half of the overall demand growth over the next 25 years. Natural gas demand for power generation is expected to increase in the near term due to additional gas power plant builds and lower coal generation. In the Long run, power generation gas demand is expected to decline due to higher renewable penetration, state level initiatives to pursue mandatory renewable portfolio standards and state/federal regulations that drive higher energy efficiency and incentivize energy storage. Natural gas demand in industrial sector is expected be up slightly in the long run as gas-intensive end uses such as petrochemicals and fertilizers. In the transportation sector (compressed natural gas and LNG used in vehicles and off-road equipment), ICF expects significant penetration of electric vehicle technologies (both on road and off road) starting 2030.

Exhibit B 9 shows ICF’s U.S. and Canadian consumption forecast by sector. Under the base case, ICF assumes that 12 North American LNG export terminals will be built and/or expanded: Sabine Pass, Freeport, Cove Point, Cameron, Corpus Christi, Elba Island, Golden Pass, LNG Canada, Woodfibre, Calcasieu Pass, Costa Azul, and Driftwood LNG.

Exhibit B 9 : U.S. and Canadian Gas Consumption by Sector and Exports



* Includes pipeline fuel and lease & plant
Source: ICF GMM® Q2 2022

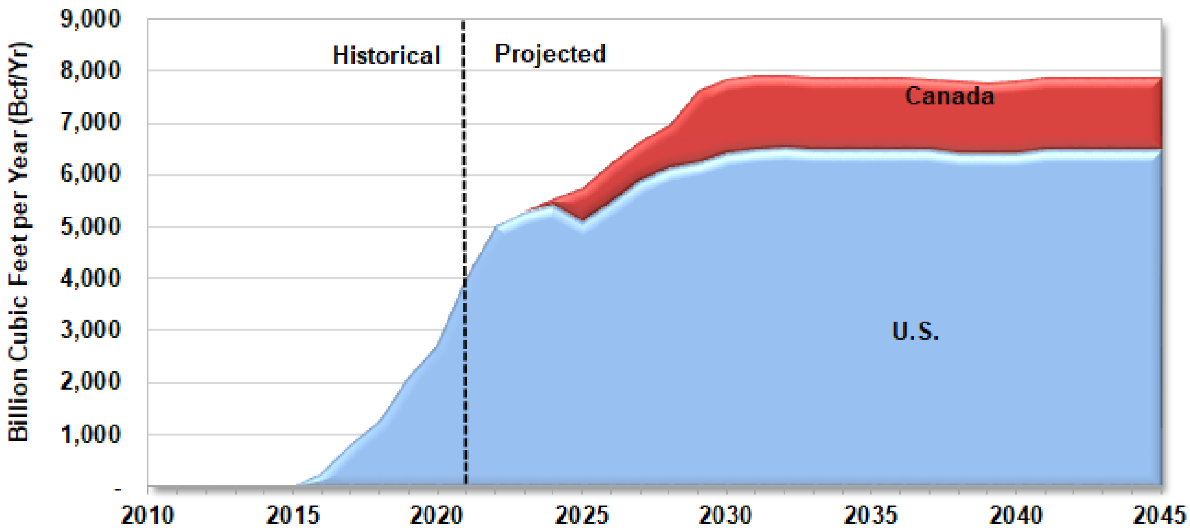
Feed gas deliveries for U.S. and Canadian LNG exports are projected to reach 7.8 Tcf per year (21.6 Bcfd) by 2045, with volumes from the Gulf Coast expected to reach 6.4 Tcf per year (17.8 Bcfd), based on ICF's review of projects approved by the Federal Energy Regulatory Commission and the Department of Energy.
Incremental power sector gas use between 2022 and 2045 is expected to decline over the period, with renewable power generation expected to increase significantly over time. Gas use for power generation will decrease from about 11.9 Tcf (32.63 Bcfd) in 2022 to 11.8 Tcf per year (32.38 Bcfd) by 2045.
Several factors the growth of gas demand for power generation in the near term. Currently, about 600 gigawatts (GW) of existing gas-fired generating capacity is available in the U.S. and Canada. Much of that capacity is underutilized and readily available to satisfy incremental electric load growth. U.S. electric load growth is based on the latest available projections from ISOs as well as forecasts from NERC. Electricity demand is projected to average 0.69% per year from 2022-2045 across the U.S., which is driven by the ISO's expected levels of demand change, including the impacts of electrification of the transportation and other sectors, as well as offsetting changes in energy efficiency adoption. ICF assumes that by 2023, consistent with Moody's estimate of economic impacts, there will be a full recovery to the forecasted demand to pre-pandemic levels. Updates to firm generation capacity additions and retirements based on announcements are as of April 2022. The ICF Base Case includes regional carbon control programs in California and for the Regional Greenhouse Gas Initiative (RGGI) states, as well as a probability-weighted national CO2 charge that is representative of federal carbon policies that may take effect between now and 2050. ICF's Base Case also reflects EPA rules governing power plants, including the Mercury & Air Toxics Standards Rule (MATS), the Cross-State Air Pollution Rule (CSAPR), and rules governing water intake structures under Clean Water Act 316(b), and coal combustion residuals (CCR, or ash).

Growth in gas demand in other sectors will be much slower than in the power sector. Residential and commercial gas use is driven by both population growth and efficiency improvements. Energy efficiency gains lead to lower per-customer gas consumption, thus somewhat offsetting gas demand growth in the residential and commercial sectors, which lead to lower per-customer gas consumption. Gas use by natural gas vehicles (NGVs) is included in the commercial sector. The Base Case assumes that the growth of NGVs is primarily in fleet vehicles (e.g., urban buses), and vehicular gas consumption is not a major contributor to total demand growth. In addition, pipeline exports to Mexico are expected to increase to over 2.8 Tcf (7.9 Bcfd) by 2045, up from 2.3 Tcf (6.3 Bcfd) in 2022.

LNG Export Trends

With an increased reliance on US LNG exports by the European Union in order to move away from Russian supplies, the U.S. export facilities are currently running at full capacity. Europe is seeking an additional 2-15 Bcfd of exports demand from across the globe. There is about 14.5 Bcfd of U.S. LNG export capacity currently in-service with another 2.5 Bcfd planned by 2025. The U.S. has an additional 30 Bcfd of export capacity that is FERC approved, which is double the potential additional demand required by Europe. However, ICF's Q2 2022 base case didn't include any additional greenfield facilities since these projects were missing long-term contracting and final investment decisions (FIDs). Based on our assessment of world LNG demand and other international sources of LNG supply, the Base Case of this study assumes that the U.S. and Canadian LNG exports reach 7.8 Tcf per year (21.6 Bcfd) by 2045. Global LNG prices are heavily influenced by oil prices. Given the current global economic climate and high oil price environment, U.S. and Canadian export volumes are projected to be about 5 Tcf per year (13.7 Bcfd) in 2022 (see exhibit below).

Exhibit B 10 : U.S. and Canadian Base Case LNG Export Assumptions

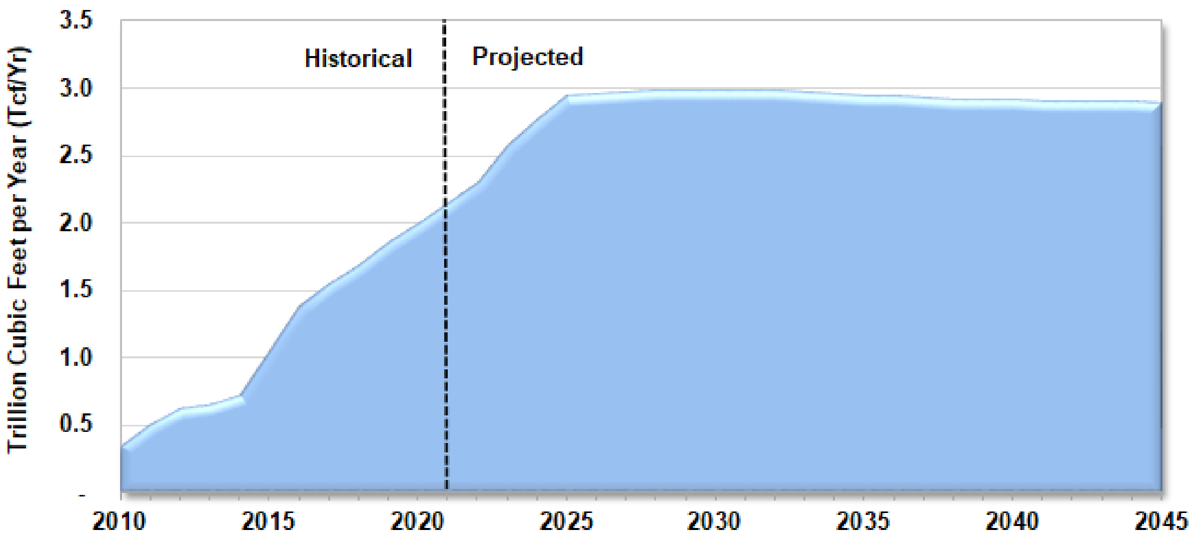


Source: ICF GMM® Q2 2022

Pipeline Exports to Mexico

Mexico's demand for natural gas continues to rise, while its domestic production has been declining. Since 2015, Mexico's imports of U.S. gas have undergone a 118% increase, reaching 6.3 Bcfd in 2022. As Mexico continues to add gas-fired generation and sponsor new pipelines from the U.S., exports will continue to grow, reaching 8.2 Bcfd by 2030 and then level off.

Exhibit B 11 : Base Case Exports to Mexico Assumptions



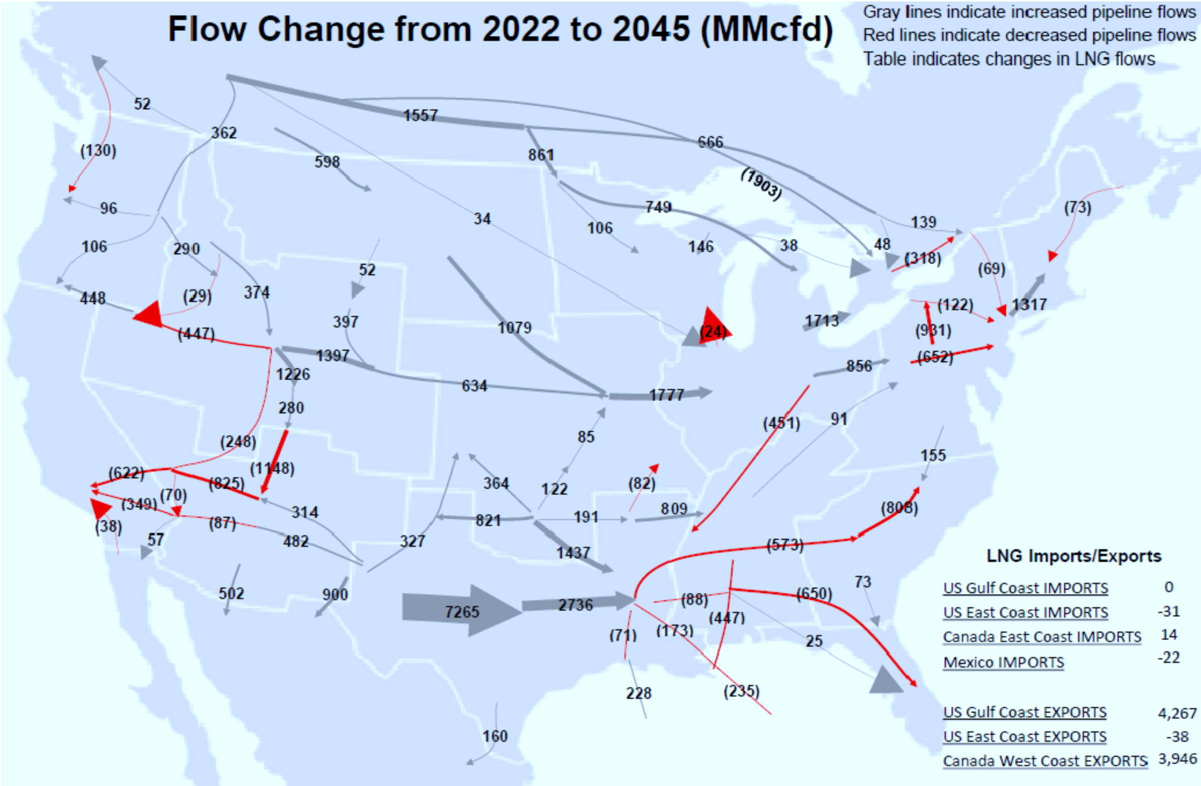
Source: ICF GMM® Q2 2022

U.S. and Canadian Natural Gas Midstream Infrastructure Trends

As regional gas supply and demand continue to shift over time, there will likely be significant changes in interregional pipeline flows. Exhibit B 12 shows the projected changes in interregional pipeline flows from 2022 to 2045 in the Base Case. The map shows the United States divided into regions. The arrows show the changes in gas flows over the pipeline corridors between the regions between the years 2022 and 2045, where the gray arrows indicate increases in flows and red arrows indicate decreases.

Exhibit B 12 illustrates how gas supply developments will drive major changes in U.S. and Canadian gas flows. Marcellus gas production growth continues to reverse flows, pushing gas toward the west and south. New developments in Midcontinent unconventional plays will increasingly flow to the Gulf Coast region. Rocky Mountain production will increasingly move westward and serve local demand. Longer term Permian production will primarily be directed to the Gulf Coast. Eastward flows out of Western Canada will continue to remain relatively low as incremental gas supplies are consumed locally or exported off of the West Coast of Canada.

Exhibit B 12 : Projected Change in Interregional Pipeline Flows

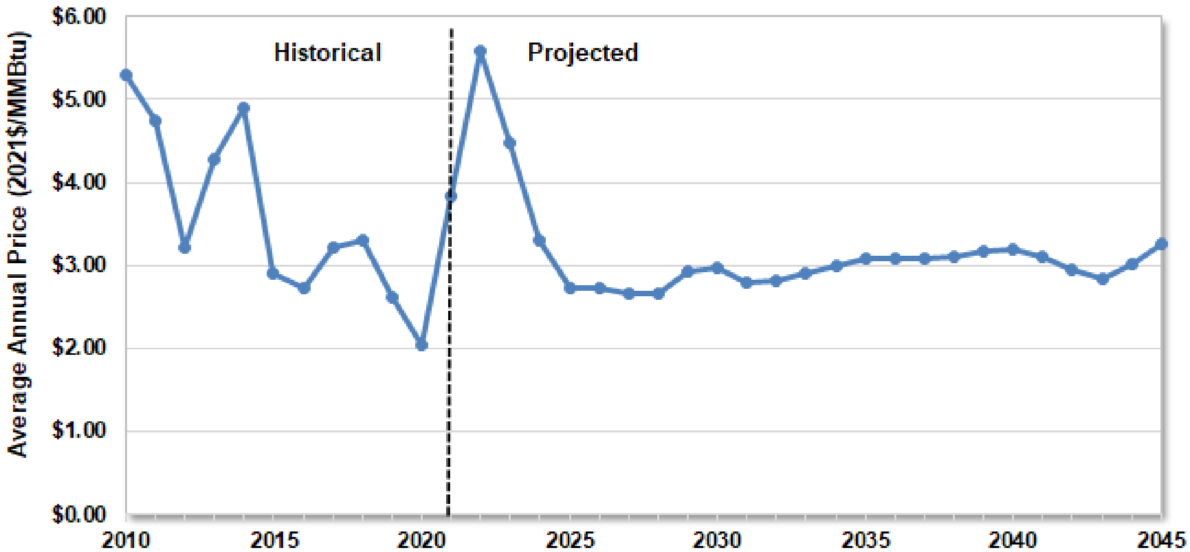


Source: ICF GMM® Q2 2022

Natural Gas Price Trends

Natural gas prices at the major market hubs in North America are forecasted to be higher in 2022 than they were in 2021 due to a significant rise in LNG exports demand, low levels of natural gas in storage, production gains slower than expected and the fluctuating weather. The Henry Hub price is projected to average \$5.57/MMBtu (in real 2021\$) in 2022 compared to \$3.82/MMBtu in 2021. The average annual price at Henry Hub is projected to be \$4.47/MMBtu in 2023, \$3.29/MMBtu in 2024 and \$2.73/MMBtu in 2025 (in real 2021\$), under normal weather conditions, as natural gas markets rebalance with increased drilling and production activities. The natural gas price at Henry Hub is projected to average under \$3.2/MMBtu in real 2021\$ over the next 25 years and are never expected to be below the 2020 prices under normal weather conditions.
Gas prices throughout the U.S. are expected to remain moderate, as shown in Exhibit B 13.

Exhibit B 13 : GMM Average Annual Prices for Henry Hub

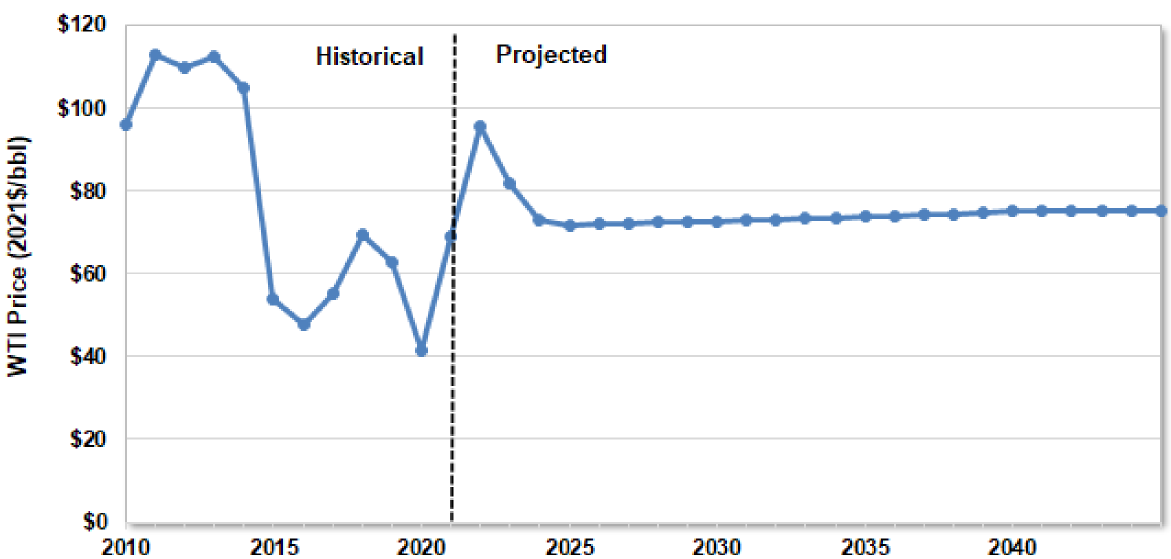


Source: ICF GMM® Q2 2022

Oil Price Trends

ICF's crude oil price forecast uses futures prices for 2022 and a blend of futures and our fundamental forecast for 2022-2025. For the long-term, ICF assumes an equilibrium marginal production cost of $70/Bbl (in real 2021$). Oil prices are higher in 2022 compared to last 7 years. European Union continues to push for a ban on Russian oil imports. This would tighten global oil supply amid expectation of higher demand from easing of China's COVID lockdowns.

Exhibit B 14 : ICF Oil Price Assumptions



Source: ICF GMM® Q2 2022

Appendix C: ICF's Gas Market Model (GMM)

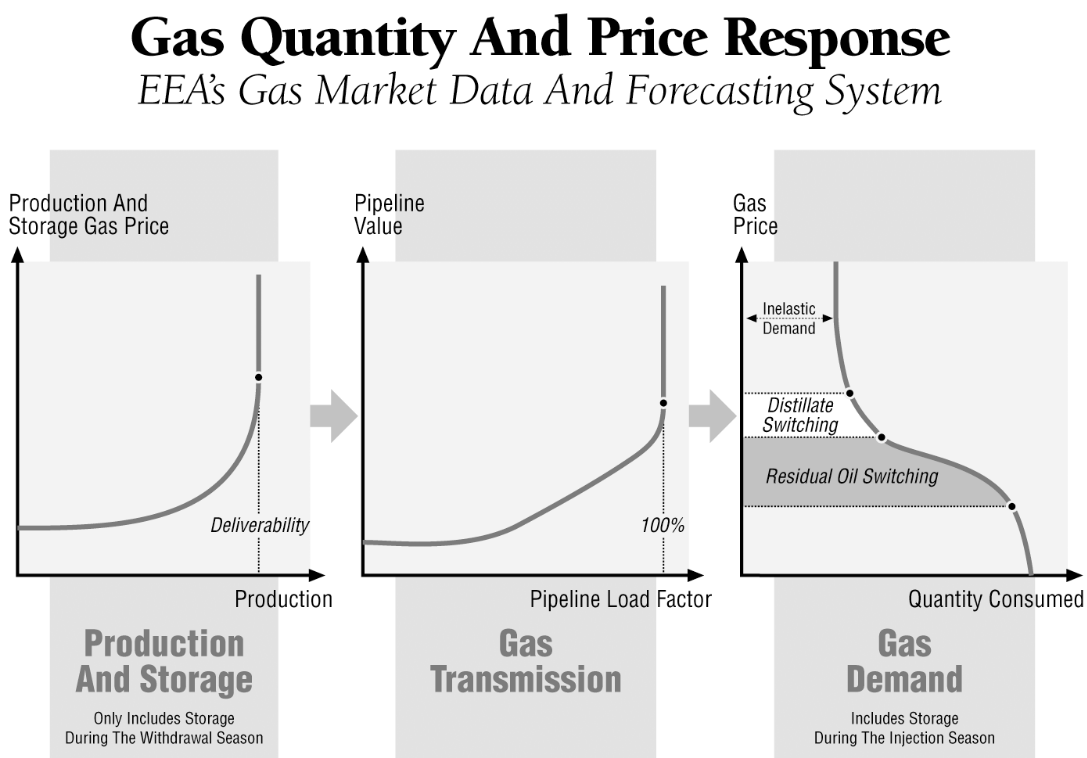
ICF's Gas Market Model (GMM) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed in the mid-1990s to provide forecasts of the U.S. and Canada natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace. Subsequently, GMM has been used to complete strategic planning studies for many private sector companies. The different studies include:

- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

In addition to its use for strategic planning studies, the model has been widely used by a number of institutional clients and advisory councils, including Interstate Natural Gas Association of America (INGAA), which has relied on the GMM for multiple studies over the past ten years. The model was also the primary tool used to complete the widely referenced study on the North American Gas market for the National Petroleum Council in 2003, and the 2010 Natural Gas Market Review for the Ontario Energy Board.

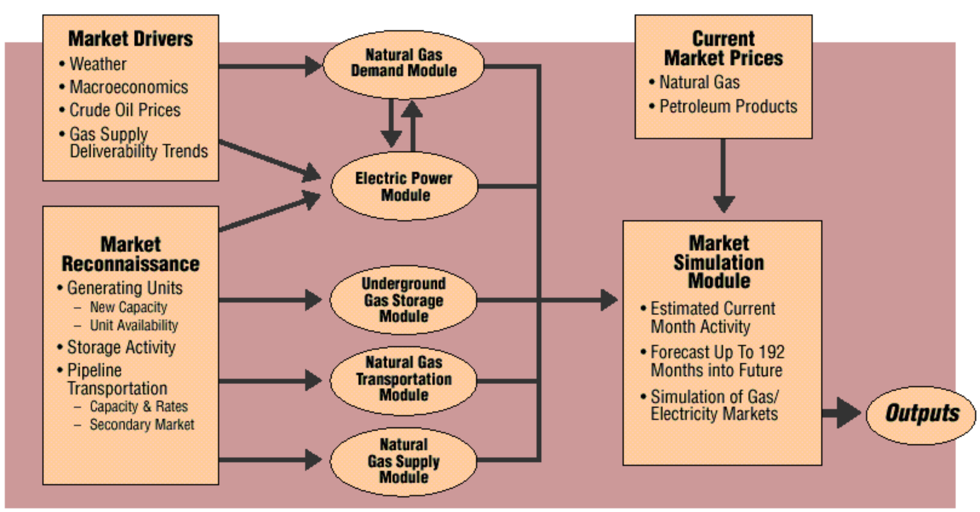
GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by scenario. Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Exhibit C 1). Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. Unlike other commercially available models for the gas industry, ICF does significant back-casting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

Exhibit C 1: ICF's Gas Market Data and Forecasting System



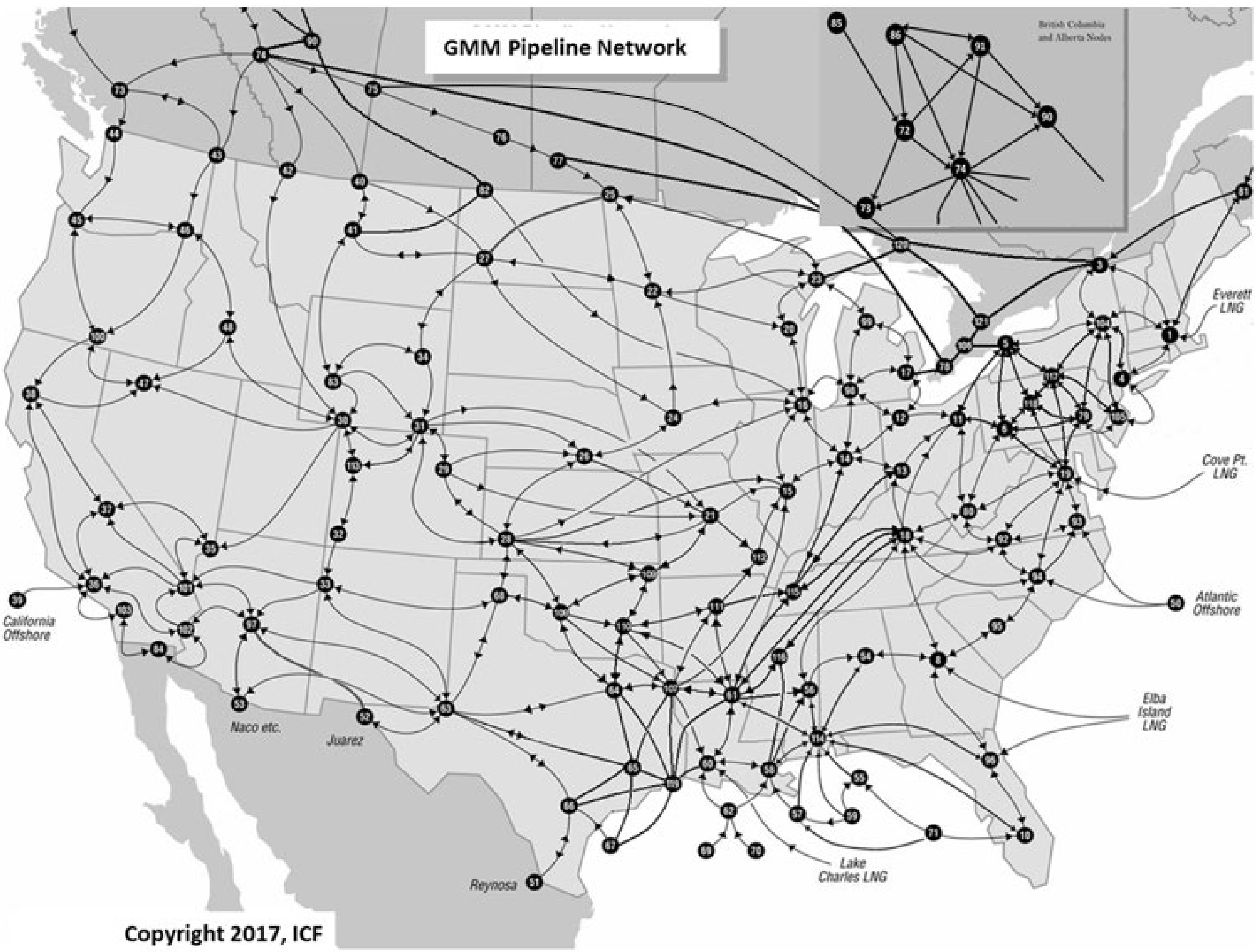
There are nine different components of GMM, as shown in Exhibit C 2. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

Exhibit C 2 : GMM Components



The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Exhibit C 3. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import and export levels. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

Exhibit C 3: GMM Transmission Network



Appendix D: Ontario Market Based Storage Contract Database

The market-based storage deliverability value analysis in section 3 of this report is based on an analysis of storage contract data developed by combining multiple data sources. These data sources include:

1) The Enbridge Gas index of storage customers https://www.enbridgegas.com/-/media/Extranet-Pages/Storage-and-transportation/operational-information/Index-of-customers/Storage_Report.ashx?rev=f1cbc47f701341bc98c29f353995a70d&hash=3C14D646A2882C749640BD536C2EF7F8
2) The Enbridge Gas's Semi-Annual Storage Report (STAR) for the period from March 1, 2021 to August 31, 2021: STAR storage report for October 2021.xlsx (enbridgegas.com)

The STAR report provides unit rates and total revenue for each storage contract, along with the customer's name. ICF used this data to calculate the capacity associated with each contract. The Index of Customer database provides space and deliverability information for each storage contract, along with the customer's name. ICF combined the records from these two public reports by matching customer names and contract capacity in order to develop a database of storage contracts with price, space, and deliverability.

ICF also included in the regression analysis the prices, space, and deliverability data from third party storage offers provided to Enbridge Gas in response to RFPs for storage services. These records are confidential in nature and not included in this report.

Appendix E: Incremental Value of Storage Relative to Gas Purchases at Dawn

Gas purchases at Dawn are not a perfect substitute for holding natural gas storage capacity. Storage capacity provides additional value on a daily basis relative to purchases at Dawn in several different areas. These include:

1) Contribution of Storage Deliverability to Design Day Capacity Requirements. Storage deliverability provides a direct contribution to design day system capacity requirements. In the Gas Supply Planning model analysis, changes in storage capacity are addressed through incremental purchases at Dawn. However, purchases at Dawn do not have the degree of reliability provided by storage deliverability. The different in reliability provides significant economic benefit to the use of incremental storage that is not captured in the Gas Supply Planning model analysis.

2) Value of Daily Gas Supply Purchasing Flexibility. Storage capacity allows for a more flexible gas purchasing approach that allows the utility to shift purchases on high priced days to purchases on lower priced days. This provides a direct economic benefit to the use of storage that is not captured in the use of storage to address aggregate excess requirements, or through the use of monthly average prices.

Value of Storage Deliverability

A change in the use of market-based storage to service bundled service customers would change the reliability of natural gas supply during peak periods. In order to assess the value of this change, ICF looked at the cost of replacing lost deliverability from natural gas storage with delivered services. Based on our assessment of the market, the cost of very high deliverability market-based storage at Dawn likely would set the initial cost of delivered services. Using the ICF assessment of the likely cost of deliverability associated with high deliverability storage ICF estimated an initial cost of delivered services at \$3.72/GJ/Day for 10 days of delivered services. This is reflected in the storage price analysis described below. In this analysis, a change in storage capacity of one PJ would lead to a reduction in storage deliverability of 0.012 PJ. The cost of replacement deliverability is estimated to be \$0.41 per GJ of storage capacity per year. [34],[35]

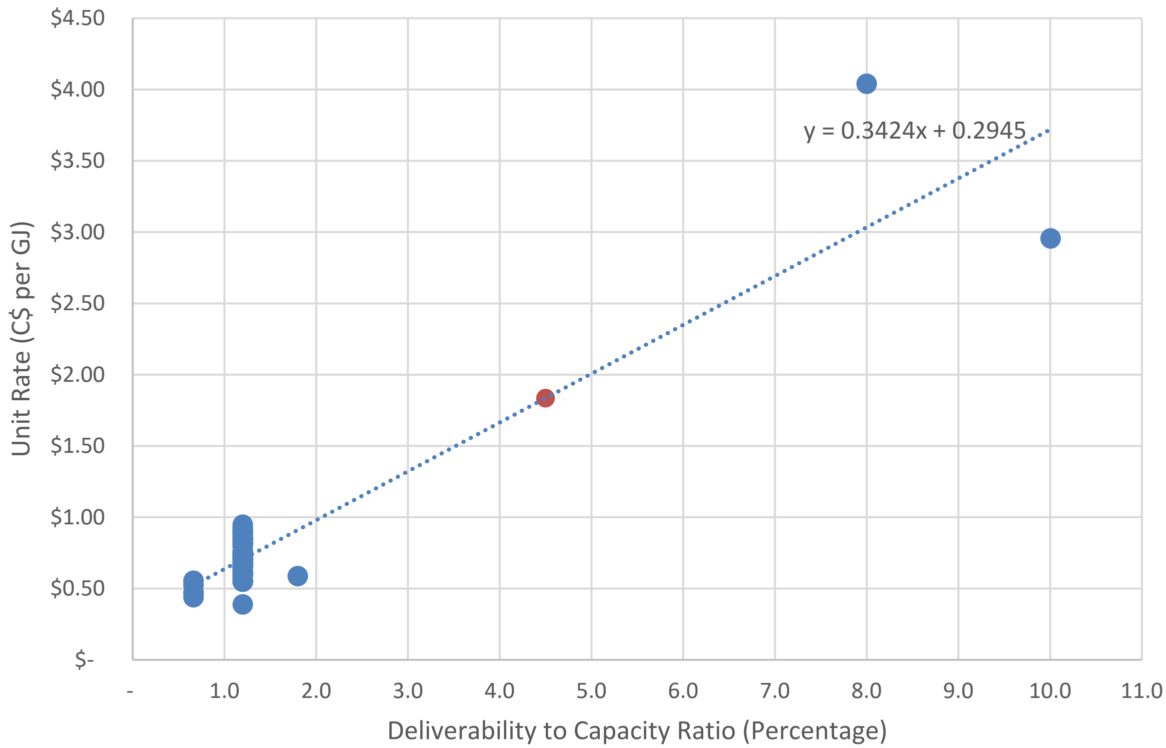
The storage price analysis is based on historical data on market-based storage contracts from the Enbridge Gas storage STAR Report[36] and the Enbridge Gas Storage Holders Index of Customers[37] to create a database of market-based storage contracts with capacity, deliverability, and rates. ICF also included responses to recent Enbridge Gas RFPs for market-based storage in the storage contract value database. ICF used the integrated storage contract value database to conduct a regression analysis of the value of storage based on the space and deliverability characteristics in each contract.[38] The results of the regression analysis are shown in Exhibit E 1. The contract database used in this analysis is included in Appendix D to this report.

Contribution from Short Term Price Volatility on Storage Value

Incremental storage capacity above the level indicated by the Aggregate Excess methodology also increases the utility's ability to optimize purchase patterns, including reducing purchases at Dawn at the highest priced days and increasing purchases at Dawn on days with lower prices. Over the last five years (2018 – 2022), the highest priced day in January has averaged about US\$1.71 per MMBtu higher than the average January price. The lowest price day in January has averaged about \$0.48 per MMBtu below than the average January price. Hence the ability to shift purchases from the highest cost day to the lowest cost day in January would reduce gas purchase costs by \$2.19 per MMBtu. Achieving this degree of cost savings is unlikely to be feasible. However, it would be reasonable to expect a degree of cost savings associated with the flexibility in supply purchase timing associated with incremental storage capacity. ICF calculated a rough assessment of the potential savings to be C\$106,522 per year per PJ of storage capacity based on the ability to shift five days per month of high-priced purchases to the average monthly price excluding the five highest price days. The monthly average prices and the 5-day high prices at Dawn are shown in Table E 1.

[34] Excluding the value associated with storage space.
[35] Based on 1.2 percent deliverability. (1.2 * 0.3424) + (0.2945*0) = \$0.41 per GJ
[36] STAR storage report for October 2021.xlsx (enbridgegas.com)
[37] https://www.enbridgegas.com/-/media/Extranet-Pages/Storage-and-transportation/operational-information/Index-of-customers/Storage_Report.ashx?rev=298043dc1c2241c9abf2a8a4ac8aa2d2&hash=9DA9849B78F15C206654F1E299C018B7
[38] Two high deliverability storage contracts with deliverability exceeding 10% of the storage space were excluded from the regression analysis. These contracts were designed to provide a specific service to power generation customers and were considered outliers for this analysis. Inclusion of these outliers would have increased the cost of the market-based services and delivered services estimated in this report and have reduced the cost effectiveness of these alternatives to this analysis .

Exhibit E 1 : Scatter Plot of Enbridge Gas Storage Contracts' Unit Rate and Deliverability to Capacity Ratio



Incremental Storage Value

Overall ICF estimated that the value of firm peak period incremental deliverability associated with storage capacity would increase the value of storage by $410,880 per PJ of storage capacity, while the ability to avoid purchases during the highest priced market periods would increase the value of storage by at least $106,522 per year.[39] Together, these two value streams increase the value of incremental storage capacity by at least $517,402 per PJ of storage capacity per year.

[39] The value of the ability to avoid purchases during the highest price periods reflects a small portion of the extrinsic value of storage that could be achieved through the use of the storage capacity for daily price arbitrage. ICF has not calculated the extrinsic value of storage as part of this analysis.

Table E 1: Monthly Average prices and the 5-day high Prices at Dawn (US$/ MMBtu)

Average Monthly Price of Gas at Dawn Ex 5 Highest Price Days (US$/MMBtu)					
Year	**2018**	**2019**	**2020**	**2021**	**2022**
January	3.5	2.9	1.9	2.5	4.0
February	2.6	2.6	1.7	3.5	4.4
March	2.5	2.8	1.6	2.5	4.6
April	2.8	2.4	1.6	2.5	6.3
May	2.6	2.4	1.6	2.7	7.7
June	2.8	2.1	1.6	3.0	7.2
July	2.8	2.1	1.7	3.5	6.5
August	3.0	2.0	2.0	3.8	8.2
September	2.9	2.1	1.7	4.7	
October	3.3	1.8	1.9	5.1	
November	4.1	2.5	2.3	4.9	
December	3.7	2.2	2.4	3.7	
Average of Five Highest Price Days of Gas at Dawn (US$/MMBtu)					
Year	**2018**	**2019**	**2020**	**2021**	**2022**
January	6.3	3.8	2.1	2.7	4.8
February	3.0	3.0	1.8	6.4	5.2
March	2.6	4.3	1.7	2.7	5.2
April	3.8	2.6	1.8	2.7	7.1
May	2.8	2.5	1.9	2.8	8.5
June	2.9	2.3	1.7	3.4	8.7
July	2.8	2.3	1.8	3.8	8.4
August	3.1	2.1	2.2	4.1	8.9
September	3.0	2.4	2.1	5.2	
October	3.5	2.4	2.9	5.8	
November	4.9	2.8	2.8	5.4	
December	4.6	2.4	2.6	4.2	
Difference Between 5 Highest Price Days of Gas at Dawn and Monthly Average Ex 5 Highest Price days (US$/MMBtu)					
Year	**2018**	**2019**	**2020**	**2021**	**2022**
January	2.8	0.8	0.2	0.2	0.8
February	0.4	0.3	0.1	3.0	0.8
March	0.1	1.5	0.2	0.2	0.6
April	1.0	0.2	0.2	0.2	0.8
May	0.2	0.1	0.2	0.1	0.8
June	0.1	0.1	0.1	0.4	1.5
July	0.1	0.2	0.1	0.3	1.8
August	0.1	0.1	0.3	0.3	0.7
September	0.1	0.3	0.4	0.6	
October	0.2	0.6	1.0	0.7	
November	0.8	0.2	0.5	0.5	
December	0.9	0.2	0.2	0.4	
Annual Average	0.6	0.4	0.3	0.6	1.0

OPERATIONAL CONTINGENCY

STEVEN PARDY, MANAGER UNDERGROUND STORAGE & TRANSMISSION PLANNING

1. Enbridge Gas has updated this evidence to reflect that the following issue is being addressed in Phase 2 of this Application.

   18 c) Is the proposed harmonized approach to determining gas costs (design day, operational contingency space, unaccounted for gas, Parkway Delivery Obligation) appropriate?

2. Issue 18, part c) was partially settled as part of the Phase 1 Settlement Proposal approved by the OEB on August 17, 2023, for determining gas costs, except for the amount of operational contingency space to be determined in Phase 2.

3. The purpose of this evidence is to request OEB approval for operational contingency space and molecule requirements to be included in delivery rates. Impacts on the Gas Supply Plan, including cost and risk implications of these proposals, are discussed at Phase 2 Exhibit 4, Tab 2, Schedule 1.

4. This exhibit provides an overview of Enbridge Gas's requirement for 15.6 PJ of operational contingency space, which is comprised of 4.8 PJ of empty space reserved at the end of the injection season, and a minimum inventory (space and molecules) level of 10.8 PJ through the end of the withdrawal period reserved to support the reliability and resilience of the Enbridge Gas storage, transmission, and distribution systems.

5. The proposed 15.6 PJ of operational contingency space is 7.4 PJ less than the current total combined operational contingency space of 23.0 PJ for the EGD and Union rate zones. Additionally, the combined operational contingency molecule requirements are reduced from 15.5 PJ to 10.8 PJ.

6. Enbridge Gas has proposed to apply inventory targets embedded within its storage portfolio to manage the 15.6 PJ of operational contingency requirements. This effectively reserves 15.6 PJ of storage space exclusively for operational contingency purposes and therefore, cannot be used to serve customer demands during the winter. Please see Phase 2 Exhibit 4, Tab 2, Schedule 1 for information on how operational contingency will be managed through the Gas Supply Plan.

7. This evidence is organized as follows:
    1. Rationale for Operational Contingency
    2. Historical Operational Contingency in Rates
    3. Proposed Operational Contingency and Allocations
    4. Summary

1. Rationale for Operational Contingency

8. As an integrated storage, transmission, and distribution system operator, Enbridge Gas requires operational contingency space and molecules to support the storage, transmission, and distribution services provided to all customers, both in-franchise and ex-franchise. Operational contingency space and molecules support the operation of the system by providing the reserve capacity and operational balancing capability necessary to manage the services provided by Enbridge Gas and ensures the reliability and resilience of the Enbridge Gas storage, transmission, and distribution systems. Specifically, operational contingency space and molecules includes space (empty space) at the end of the injection season and space and

molecules (filled space) at the end of the withdrawal season to support the operation of the system.

9. Operational contingency space and molecules are critical to the reliability and resilience of the storage system. Managing receipts and deliveries during the end of the injection season (October and November) and the end of the withdrawal season (March and April) becomes increasingly difficult as temperatures can vary considerably during those periods of the year. Enbridge Gas must leave empty space at the end of the injection season in order to inject gas supply that is no longer being consumed by end-use customers due to sudden changes in weather. Similarly, Enbridge Gas must maintain filled space at the end of the withdrawal season in case there are sudden weather variances and Enbridge Gas is unable to purchase additional supply in time to meet customer requirements. In this scenario, the incremental customer demands would need to be met through storage withdrawals facilitated by this operational contingency filled space.

10. The 4.8 PJ of empty space is required for the end of the injection season to help manage unplanned events related to weather variances, storage pool factors and operational balancing agreement (OBA) imbalances. The empty space is most critical in October and November until the storage system is on sustained withdrawals. The last 4.8 PJ of empty space will remain empty throughout the withdrawal season since available supply beyond the end of injections will be utilized to meet customer demands. Purchasing additional supply to fill this space is unnecessary and will lead to higher gas supply costs since additional winter supply is more expensive than summer supply.

11. The 10.8 PJ of filled space is required for the end of the withdrawal season to help manage unplanned events related to weather variances, system linepack, storage

pool factors and OBA imbalances. The filled space is most critical in March and April until the storage system is on sustained injections. The last 10.8 PJ of filled space will remain full throughout the injection season since it is not necessary to remove this gas from storage while the remainder of the storage system is on injection.

12. Gas Supply is proposing to incorporate operational contingency requirements as inventory targets within the Gas Supply Plan. This means that the plan will set a constraint to ensure that the last 4.8 PJ of empty space will remain empty. Additionally, a minimum inventory constraint of 10.8 PJ will ensure that the storage inventory will remain in place. Therefore, the total amount of space that is allocated for operational contingency is 15.6 PJ.

2. Historical Operational Contingency in Rates

13. To manage Union's integrated operations, it was determined in Union's 1999 Rates[1] proceeding that 9.7 PJ would be allocated for operational contingency[2]. As part of Union's Gas Supply Plan, operational contingency space requirements were included within its portfolio of cost-based storage in addition to the storage requirements determined by the aggregate excess calculation. In Union's 2013 Rates proceeding[3], operational contingency space for the Union rate zones was revised to 9.5 PJ to reflect updated data. This was separated between Union North and Union South as shown in Table 1.

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[1] E.B.R.O. 499, Decision with Reasons, January 20, 1999.
[2] Operational contingency was previously referred to as system integrity by Union.
[3] EB-2011-0210, Decision and Order, October 24, 2012.

Table 1
Union Operational Contingency Space Requirements

Line No.	Rate Zone (PJ)	1999 OEB-Approved	2013 OEB-Approved
		(a)	(b)
1	Union South	9.1	8.9
2	Union North	0.6	0.6
3	Total	9.7	9.5

14. In addition, the total requirements for operational contingency were determined using various components as follows: forecast weather variances, UFG forecast variances, system linepack, storage pool hysteresis, OBA/load balancing agreement (LBA) imbalances, and supply backstopping. In Union's 2013 Rates proceeding[4], these components were allocated as shown in Table 2.

Table 2
Union Historical Operational Contingency Components

Line No.	Particulars (PJ)	2013 OEB-Approved
		(a)
1	Forecast Weather Variances	2.6
2	UFG Forecast Variances	2.2
3	System Linepack	1.1
4	Storage Pool Hysteresis	2.0
5	OBA/LBA Imbalances	0.9
6	Supply Backstopping	0.7
7	Total	9.5

15. The EGD rate zone operational contingency space and molecule requirements are managed differently than the Union rate zones. While the Union rate zones reserved storage space for operational contingency, the EGD rate zone managed

[4] EB-2011-0210.

operational contingency through injection and withdrawal targets rather than procuring incremental storage space for operational contingency purposes. On injection, EGD planned to leave 4 PJ of empty space to manage the system. On withdrawal, EGD did not plan to fully empty its storage space. Enbridge Gas is planning for 9.5 PJ of gas to be in storage (filled space) for the EGD rate zone at the end of Winter 2023/2024. Therefore, based on historical methods, the EGD rate zone will have a total of 13.5 PJ of space and 9.5 PJ of molecules available for operational contingency for Winter 2023/2024.

16. The total EGD and Union rate zone space and molecules available for operational contingency for Winter 2023/2024, based on historical methods, is 23.0 PJ as shown in Table 3.

Table 3
Operational Contingency Based on Historical Methods

Line No.	Particulars (PJ)	Union Rate Zones	EGD Rate Zone	Total
		(a)	(b)	(c) = (a) + (b)
1	Empty Space	3.5	4.0	7.5
2	Filled Space and Molecules	6.0	9.5	15.5
3	Total	9.5	13.5	23.0

3. Proposed Operational Contingency and Allocations

17. Enbridge Gas used a model to determine the amount of operational contingency space and molecules required to support its harmonized storage and transportation services. The model uses historical data from the Enbridge Gas system to determine the amount of operational contingency space and molecules required for each of the operational contingency components shown in Table 4. Each component is modeled separately to determine the total operational contingency space and molecule requirements. The operational contingency model accounts for

the fact that the component events related to the operational contingency may not all occur at the same time, thus reducing the total operational contingency requirement.

18. The total operational contingency requirement was determined to be 15.6 PJ of space and 10.8 PJ of molecules. The empty space and filled space for each operational contingency component is shown in Table 4.

Table 4
Enbridge Gas Proposed Operational Contingency Components

Line No.	Particulars (PJ)	Empty Space	Filled Space	Total Space
		(a)	(b)	(c) = (a) + (b)
1	Weather Variances	2.9	5.0	7.9
2	System Linepack	0.0	1.3	1.3
3	Storage Pool Factors	1.3	3.5	4.8
4	OBA Imbalances	0.7	0.9	1.6
5	Total	4.8	10.8	15.6

19. Each component of the operational contingency model is described below. The weather variance component appears much larger in this proposal as compared to the Union operational contingency from Table 2 due to the relatively larger residential customer base in the EGD rate zone. The EGD rate zone is more than twice as sensitive to temperature as the Union South rate zone due to a higher portion of demand related to general service customers.

20. Both utility and non-utility customers benefit from some components of operational contingency. The allocation of cost-based storage costs associated with operational

contingency are determined through the cost allocation study[5]. There is also a non-utility cross charge for the unregulated storage business for the use of utility assets to provide operational contingency. The 2024 Cost Allocation Study and the determination of the non-utility cross charge for operational contingency (which is also based on 2024 Cost Allocation Study) will be addressed as part of Phase 3 of this Application.

21. Additional information on each of the operational contingency components is discussed in the following paragraphs. The amount of empty space and filled space for each component is shown in Table 4.

Weather Variances

22. Weather variances account for differences between actual and forecast weather leading to unplanned injections and withdrawals that the system operator must manage. To mange the weather variances Enbridge Gas requires empty space during the injection season and filled space (space and molecules) during the withdrawal season. This component provides operational contingency for in-franchise general service customers since their daily storage requirements are determined based on short-term weather forecasts[6].

23. To determine the operational contingency space (empty space) required for injection, variances in weather data for the final 10 days of the injection season is used. As storage pools are filled, pools are shut-in for stabilization. This stabilization period is critical to the ongoing inventory monitoring and operation of the storage

[5] The costs associated with operational contingency were last determined in the 2013 Cost Allocation Study for the Union rate zones (EB-2011-0210).

[6] Non-utility storage customers contract for firm storage service and are required to nominate their daily storage injection and withdrawal requirements and therefore, the system operator is not taking any weather risk associated with their storage demands.

pools. As pools are shut-in during the latter part of the injection season, the number of pools available for injections is reduced. As a result, managing October and November gas receipts becomes increasingly difficult as temperatures can also vary considerably at this time of year. Weather that is warmer than forecasted will require more injections than planned, and a large daily variance requires accessible space for operational contingency purposes.

24. The operational contingency space and molecules (filled space) required for the withdrawal season is determined by using weather data throughout the withdrawal season. Daily gas requirements are determined based upon a weather forecast prepared prior to the beginning of the gas day. Weather that is colder than forecasted will require additional gas from storage than planned.

System Linepack

25. Changes in system linepack due to unexpected upsets (in-system, upstream and downstream) and unplanned system demands may result in withdrawals from storage to replenish linepack on Enbridge Gas transmission systems and large distribution laterals. Operational contingency provides the space and molecules (filled space) necessary to meet the unplanned demand in the winter season due to changes in linepack. This component provides operational contingency for in-franchise customers and ex-franchise transportation customers that use the transmission systems and large distribution laterals.

26. To determine the operational contingency space and molecules (filled space) required during the withdrawal season, daily linepack data was used to determine the incremental demand associated with linepack that could be required throughout the winter season.

Storage Pool Factors

27. The storage pool factors component was previously called storage pool hysteresis and has been renamed to account for additional factors relating to the operation of the Enbridge Gas storage system. Storage pool factors include: storage pool hysteresis, storage pool deliverability coefficients and storage pool variances. This component requires both empty space and filled space and provides operational contingency for all customers who use storage.

28. The storage pool hysteresis factor forms part of the model to determine the amount of operational contingency space and molecules required for the storage pool factors component. Storage pool deliverability performance is influenced by localized pressure differences across the storage pool because of withdrawal and injection operations. These pressure differences are referred to as storage pool hysteresis and lead to lower storage deliverability performance.

29. Another component of the storage pool factors is attributed to storage pool deliverability coefficients. Total system deliverability is determined based upon a set of storage pool deliverability coefficients for each individual storage pool. These coefficients are known to vary from day-to-day, season-to-season and year-to-year. This variability affects the ability to accurately predict the amount of flow into or out of the storage system.

30. The final component of the storage pool factors is storage pool variances. Each storage pool in the Enbridge Gas system is shut-in twice annually to allow the pressure within the pool to stabilize. This enables Enbridge Gas to determine the storage pool variances between measured and calculated inventory. However, within the operating season, the variance in pool inventory is not fully visible to the

operator and can lead to inaccuracies in calculating the available space and molecules available for operations at a point in time.

31. The impact of these three factors is not fully known until after each operating season. The net effect of the storage pool factors is that the actual amount of gas molecules in storage, the actual amount of empty space available and the actual injection and withdrawal capabilities varies and is not fully known by the system operator. Therefore, operational contingency provides empty space and filled space to mitigate the impact of the storage pool factors during the operating season.

OBA Imbalances

32. OBA imbalances occur daily at various delivery and receipt points on the Enbridge Gas system with interconnecting pipeline operators and is caused by shippers over or under delivering their supply compared to their consumption. To the extent that OBA imbalances create a deficit on the Enbridge Gas system on any given day, an equivalent volume from storage is required to balance supplies and demands on the Enbridge Gas system. Operational contingency empty space is utilized to store additional gas from OBA imbalances during the injection season and operational contingency filled space is utilized during the withdrawal season to provide the molecules necessary to meet increased demand from OBA imbalances. This component provides operational contingency for all customers taking service on Enbridge Gas's system, including in-franchise, ex-franchise transportation and non-utility storage customers.

Previous Factors (No Longer Included)

33. UFG forecast variances and supply backstopping components are no longer required to be part of the operational contingency methodology. Existing processes are used to manage UFG variances and supply disruptions.

4. Summary

34. The total operational contingency space and molecules required for the Enbridge Gas storage, transmission and distribution systems will be reduced from 23.0 PJ, based on historical methods, to 15.6 PJ, based on the proposed methodology. Additionally, as outlined in Phase 2 Exhibit 4, Tab 2, Schedule 1, Enbridge Gas proposes to use inventory targets so that incremental storage space is not required to meet operational contingency requirements. This method reserves 15.6 PJ of storage space within the storage space calculated by aggregate excess and therefore, cannot be used to serve customer demands during the winter.

35. The proposed operational contingency space accounts for the fact that the events related to the individual components (weather variances, system linepack, storage pool factors, OBA imbalances) will not all occur at the same time. This results in less operational contingency space and molecules being required.

36. 4.8 PJ of empty space is required on November 1 each year to manage late season injection requirements. The 4.8 PJ of empty space is required to manage weather variances, storage pool factors and OBA imbalances.

37. 10.8 PJ of filled space (space and molecules) is required to meet winter season operational requirements, including late season withdrawal requirements, to manage impacts resulting from weather variances, system linepack, storage pool factors and OBA imbalances.

UTILITY STORAGE INJECTION AND WITHDRAWAL CAPABILITY
ADAM STIERS, MANAGER CAPACITY MANAGEMENT & UTILIZATION

1. Enbridge Gas has included this evidence to reflect the following issue which is being addressed as part of Phase 2 of this Application.

   39) Is the proposed harmonized methodology for determining the amount of storage space and deliverability among customers appropriate and is the proposed allocation of storage space and deliverability among customers appropriate?

2. The purpose of this evidence is to provide the amount of firm injection and withdrawal capability available to serve in-franchise customers, which includes maximum firm withdrawal and dehydration capability of 3.8 PJ/d and maximum firm injection capability of 1.7 PJ/d associated with the utility storage space of 199.7 PJ[1]. Operationally, withdrawal capabilities decrease based on inventory levels[2]; as inventory levels decrease so does withdrawal capability. Similarly, injection capability decreases as inventory increases. The utility storage space capacity was set in the OEB Natural Gas Electricity Interface Review (NGEIR).

3. Storage injection and withdrawal capabilities support the formulation of the Gas Supply Plan, the cost allocation study, and Enbridge Gas's operational contingency space for the 2024 Test Year Forecast, as provided at Phase 2 Exhibit 4, Tab 2, Schedule 1, Exhibit 7[3] and Phase 2 Exhibit 4, Tab 2, Schedule 4

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[1] This includes 0.3 PJ of storage related to the Crowland storage facility.
[2] EB-2014-0276, Exhibit TCU1.1.
[3] Exhibit 7 relates to Issue 24 on the issues list of this Rebasing proceeding; Cost Allocation. Pursuant to the Settlement Agreement, matters related to Cost Allocation have been moved to Phase 3 of this Rebasing Proceeding.

4. This evidence is organized as follows:
    1. Background
    2. Utility Storage Injection and Withdrawal Capability
    3. Summary

1. Background

5. The NGEIR Decision[4] in 2006 established the allocated amount of utility storage space EGD and Union were required to reserve at cost-based rates for in-franchise customers. EGD was directed to continue to provide its 99.7 PJ of existing storage space for in-franchise customers[5] and Union was directed to reserve 100 PJ of its storage space for in-franchise customers[6]. At the time of NGEIR, Union owned and operated approximately 160 PJ of storage space. The OEB directed that storage space owned by Union in excess of the 100 PJ constituted a non-utility asset for which the shareholders appropriately bear the risk.[7] On a combined basis, the cost-based storage space available to provide service to Enbridge Gas in-franchise customers is the total of the EGD and Union amounts reserved for in-franchise customers of 99.7 PJ and 100 PJ, respectively, or 199.7 PJ in total for Enbridge Gas.

6. Any injection and withdrawal capabilities at Tecumseh at the time of the NGEIR Decision were reserved for utility use and those capabilities have continued to be used to serve in-franchise customers. The maximum firm withdrawal capability from

[4] EB-2005-0551, Decision with Reasons, November 7, 2006.
[5] Ibid, p.11. The NGEIR Decision reserved 99.4 PJ of storage space for EGD in-franchise customers. In addition, 0.3 PJ of cost-based storage space related to the EGD Crowland storage facility was not included at the time of the OEB NGEIR Decision for a total of 99.7 PJ.
[6] Ibid, p.83.
[7] Ibid, p.4.

EGD storage operations to serve in-franchise customers is 1.9 PJ/d, and the maximum firm injection capability is 0.8 PJ/d to serve in-franchise customers.[8]

7. Prior to, and at the time of the NGEIR Decision, Union sold storage services that were deemed to be non-utility. Union also had more firm withdrawal capability than required to serve in-franchise needs at the time. The costs related to firm withdrawal and injection capability were allocated to regulated and unregulated customers, which addressed the costs related to excess withdrawal and injection capability. To allocate regulated and unregulated costs following NGEIR, Union used cost allocation methodologies consistent with the approved 2007 Cost Allocation Study[9]. This allocation was the basis for the one-time separation of existing storage and general plant assets between the utility and non-utility businesses. Storage costs related to Union assets that provided withdrawal, dehydration and injection capability were allocated using these methodologies.

8. The OEB affirmed that the use of the cost allocation methodologies in the one-time separation of Union plant assets was appropriate:

> The Board finds that Union has appropriately applied its 2007 Cost Allocation Study for the one-time separation of plant.
>
> The Board notes that the non-utility storage allocation factor utilized by Union is in accordance with the NGEIR Decision. The Board's Decision in NGEIR stated at page 74, "We also conclude that Union's current cost allocation study is adequate for the purposes of separating the regulated and unregulated costs and the revenues for ratemaking purposes."

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[8] EB-2022-0086, Exhibit B, Tab 2, Schedule 1, March 21, 2022, p.6.
[9] EB-2005-0520, Decisions with Reasons, June 29, 2006.

> The Board also notes that the fundamental premise upon which the non-utility storage allocation factor was developed is appropriate. Union’s cost allocation methodology was formulated in a manner which reflects how particular systems were designed when they were built and assigns the related costs on that basis.[10]

9. Subsequent to the NGEIR Decision, EGD and Union constructed several storage projects that increased total storage space and firm injection and withdrawal capability. The cost and risk of these storage projects has been borne strictly by the non-utility business. This allocation approach is consistent with the OEB’s NGEIR findings:

> … any new storage which is developed by the utilities will be included as part of the competitive market. The utilities will bear the risk of these investments, not ratepayers.[11]

10. Since NGEIR, Enbridge Gas has made significant capital investment to increase non-utility withdrawal capability at Dawn by 1.0 PJ/d and injection capability of 0.6 PJ/d with all associated costs allocated to the non-utility business. Over the same period, post 2007, demand for firm storage withdrawals to serve in-franchise customers has increased, exceeding 2 PJ/d in February 2019 for the Union rate zones. Enbridge Gas did not withhold any firm storage withdrawals to serve in-franchise customers and instead, reduced the maximum firm withdrawals available to serve the non-utility market. The firm withdrawal demands on design day for the Union rate zones are provided at Table 1.

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[10] EB-2011-0038, OEB Decision and Order, January 20, 2012, p.11.
[11] EB-2005-0551, Decision with Reasons, November 7, 2006, p.70.

Table 1
Forecast Firm Design Day Withdrawal Demands – Union Rate Zones

Line No.	Winter (PJ/d)	In-franchise	Excess Utility	Utility	Non-Utility	Total (1)
		(a)	(b)	(c) = (a+b)	(d)	(e) = (c+d)
1	2016/2017	1.8	0.1	1.9	1.5	3.4
2	2017/2018	1.9	0.1	2.0	1.4	3.4
3	2018/2019	2.0	0.1	2.1	1.5	3.6
4	2019/2020	2.0	0.1	2.1	1.5	3.7
5	2020/2021	1.9	0.0	2.0	2.0	3.9
6	2021/2022	2.2	0.0	2.2	1.7	3.9
7	2022/2023	2.1	0.0	2.1	1.8	4.0
8	2023/2024	2.2	0.0	2.2	1.8	4.0

Note:
(1) Over time, total withdrawal demand has increased as in-franchise and non-utility demands for storage services have both increased. Non-utility capital investments total 1.0 PJ/d by Winter 2023/2024.

2. Utility Storage Injection and Withdrawal Capability

11. Enbridge Gas has stated the maximum amount of firm withdrawal, dehydration and injection capability for the storage operations for the Union rate zones as part of this Application. Those capabilities are 1.9 PJ/d for firm withdrawal and dehydration and 0.9 PJ/d for firm injection. Storage withdrawals require dehydration; therefore, design day dehydration capability is equal to the withdrawal capability. The maximum capabilities are set based on the one-time separation of existing storage and general plant assets between the utility and non-utility businesses.[12]As described above, the maximum firm withdrawal capability to serve in-franchise customers for the storage operations of the EGD rate zone is 1.9 PJ/d, and the maximum utility firm injection capability is 0.8 PJ/d.

[12] The one-time separation defined an allocation for existing storage and general plant assets but did not define the maximum firm withdrawal, dehydration and injection capacity associated with those assets.

12. The withdrawal and injection capabilities to serve in-franchise customers for the Union rate zones are consistent with the allocation of costs. Enbridge Gas took the design day capability for February 29, 2024, and subtracted the capability associated with the direct investment of non-utility firm injection and withdrawal capability since the NGEIR Decision. The remaining base capability was split between the utility and non-utility customers using the same allocation percentages used in the one-time split of storage assets, as approved by the OEB.[13] The utility withdrawal and injection capability for the storage operations for the Union rate zones is provided at Table 2.

[13] EB-2011-0038, OEB Decision and Order, January 20, 2012, p.11.

Table 2
Total Maximum Firm Withdrawal and Injection Capability – to Serve Union Rate Zone Customers

Line No.	Particulars (PJ/d)	Total	Utility	Non-Utility
		(a)	(b)	(c)
	One-Time Separation of Plant			
1	Storage Allocation Factor (1)		62.3%	37.7%
	Withdrawal/Dehydration Capability			
2	Total Shared Capability (2)	3.0	1.9	1.1
3	Direct Investment	1.0	-	1.0
4	Total Maximum Withdrawal Capability (3)	4.0	1.9	2.1
	Injection Capability			
5	Total Shared Capability (2)	1.4	0.9	0.5
6	Direct Investment	0.6	-	0.6
7	Total Maximum Injection Capability	2.0	0.9	1.1

Notes:
(1) Approved storage allocation per EB-2011-0038.
(2) Allocated in proportion to line 1.
(3) Based on design day capacity for February 29, 2024.

13. Since Winter 2017/2018, utility customers have exceeded the cost-based withdrawal and dehydration allocation of 1.9 PJ/d. The 2024 forecast of storage withdrawal and dehydration requirements to serve in-franchise customers is 2.2 PJ/d which exceeds the reserved cost-based maximum firm withdrawal and dehydration of 1.9 PJ/d as provided in Table 2.

3. Summary

14. The maximum cost-based firm withdrawal capability to provide service to Enbridge Gas in-franchise customers is the total of the capability reserved for in-franchise customers in the EGD and Union rate zones of 1.9 PJ/d and 1.9 PJ/d, respectively,

or 3.8 PJ/d in total for Enbridge Gas. As noted above, the dehydration capability is assumed to be equal to the maximum withdrawal capability of 3.8 PJ/d. Maximum cost-based firm injection capability available to the utility is the total of the EGD and Union injection capability of 0.8 PJ/d and 0.9 PJ/d, respectively, for a total injection capability of 1.7 PJ/d available to serve in-franchise customers. The Gas Supply Plan has been developed to consider these maximum firm injection, withdrawal and dehydration capabilities as provided at Phase 2 Exhibit 4, Tab 2, Schedule 1.

LOW-CARBON ENERGY IN THE GAS SUPPLY COMMODITY PORTFOLIO

STEPHANIE FIFE, TECHNICAL MANAGER NEW ENERGY SUPPLY
AMY MIKHAILA, DIRECTOR GAS SUPPLY
MARK PROCIW, SUPERVISOR LARGE COMMERCIAL INDUSTRIAL ACCOUNTS
CORA CARRIVEAU, SUPERVISOR CLIMATE POLICY

1. Enbridge Gas has included this evidence to reflect the following issue which is being addressed as part of Phase 2 of this Application:

   53) Are the specific proposals to amend the Voluntary RNG Program and to procure low-carbon energy as part of the gas supply commodity portfolio, appropriate?

2. The purpose of this evidence is to request OEB approval to procure low-carbon energy, with a focus on renewable natural gas (RNG) as part of the gas supply commodity portfolio beginning in 2026, and recover the incremental costs associated with this energy through the proposed cost recovery mechanism. In addition, Enbridge Gas has included in this evidence, updated legislation and market developments relevant to this proposal.

3. It is clear the energy transition is underway and RNG will play an important role. As outlined in Canada's Energy Future 2023 published by the Canada Energy Regulator (CER), low-carbon fuels will enable the energy system's path to net-zero.[1]

[1] Canada Energy Regulator, Canada's Energy Future 2023, p.2, Canada's Energy Future 2023: Energy Supply and Demand Projections to 2050 (cer-rec.gc.ca)

4. RNG is a low-carbon energy because the displacement of conventional natural gas with RNG reduces greenhouse gas (GHG) emissions. RNG is produced from decomposing organic matter (e.g., food waste, human and animal wastes), which creates biogas that is upgraded to pipeline quality methane. RNG is a “drop-in” fuel that can be consumed at blends up to 100 percent without compatibility issues or modification to customer equipment. RNG production offers other environmental benefits such as improving waste management through the collection and processing of organic waste material into biogas.

5. With interest for low-carbon energy supported by customer engagement results, provided at EB-2022-0200 Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 293 to 295 and 382 to 384, and direct inquiries from large volume customers, Enbridge Gas has evaluated the role that low-carbon energy can have in the gas supply commodity portfolio and is proposing a low-carbon energy program for OEB approval.

6. As the gas supply costs associated with the low-carbon energy proposal will not be incurred in 2024, the costs are not reflected in the gas cost forecast provided at Phase 2 Exhibit 4, Tab 2, Schedule 1, Attachment 1.

7. This evidence is organized as follows:
    1. Low-Carbon Energy Program Proposal
    2. Evaluation of Low-Carbon Energy as part of the Gas Supply Commodity Portfolio
    3. RNG Market Overview
    4. GHG Emissions Reporting and Reductions from RNG

1. Low-Carbon Energy Program Proposal

8. Enbridge Gas is proposing a low-carbon energy program to procure up to one percent of the planned gas supply commodity portfolio as low-carbon energy beginning January 1, 2026. Enbridge Gas proposes to increase low-carbon energy purchases by up to one percentage point each subsequent year to a maximum of up to four percent by 2029. Thereafter, Enbridge Gas will continue to target low-carbon energy purchases of up to four percent of its portfolio until approval from the OEB is granted to procure amounts above four percent.

9. Enbridge Gas proposes cost recovery for low-carbon energy through a newly proposed Low-Carbon Voluntary Program (LCVP) for large volume sales service customers and through the cost of gas supply commodity purchases. Enbridge Gas expects to offer the LCVP on a voluntary basis to large volume sales service customers beginning January 1, 2027, when the business systems to enable the program are complete. Costs not recovered from voluntary participants through the LCVP will be included in the recovery of the cost of gas supply commodity purchases for the duration of the underpinning low-carbon energy commodity contracts, including the cost premium for low-carbon energy purchases for 2026 until the LCVP can be offered to large volume customers. Enbridge Gas proposes a maximum impact on the average residential customer of $2 per month per target percentage of RNG as forecast at the time of procurement, to a maximum of $8 per target percentage of RNG procurement in 2029 from the low-carbon energy program.

10. Enbridge Gas is proposing approval of the low-carbon energy program and cost recovery proposal permanently, until such time that a change is requested and approved by the OEB. Changes to Enbridge Gas's low-carbon energy procurement

may be required where policies, regulations, codes or standards are introduced or amended, that may require procurement of low-carbon energy for different customer segments and/or at different amounts. Enbridge Gas will continue to engage customers to determine interest in low-carbon energy in the gas supply commodity portfolio and may propose changes to the low-carbon energy program at a future date based on customer feedback.

1.1. Procurement of Low-Carbon Energy

11. Currently, Enbridge Gas does not have cost recovery certainty for procurement of low-carbon energy beyond its existing Voluntary RNG (VRNG) Pilot Program. Ontario natural gas customers are at a disadvantage compared to customers in other jurisdictions as the current VRNG Pilot Program does not support the purchase of RNG with long-term contracts. Enbridge Gas is unable to compete for this supply, as recognized by VECC in the 2022 Annual Gas Supply Plan Update: "[a]s it stands today it would appear that Canada's largest gas distribution utility is unable to compete for renewable natural gas sourced within its own distribution franchise."[2] It is critical for Enbridge Gas to have the regulatory support to meaningfully participate in the low-carbon energy market, with a current focus on RNG, through a cost-recovery mechanism that allows for larger volume and longer-term contracts. Without this support, Ontario customers will be left out of this critical opportunity to lower their emissions.

12. It is critical that Enbridge Gas secure meaningful quantities of RNG and other low-carbon energy sources under long-term contracts to ensure that Ontario customers can benefit from economical RNG supply projects. Given current market dynamics, without the ability for Enbridge Gas to commit to larger volumes and longer terms,

[2] EB-2022-0072, VECC Submission, May 24, 2022.

entities in other jurisdictions will be the first to secure the RNG production and associated benefits. RNG is in demand in various jurisdictions including Quebéc, British Columbia and the United States with mandates and supporting programs in place. Delays in the ability of Enbridge Gas to secure larger volumes and longer terms will increase the price as existing supply is contracted to meet the demand in other jurisdictions. As RNG is typically purchased via long-term contracts, these other jurisdictions will continue to maintain this position in the market for many years. As the federal carbon charge (FCC) increases and the benefit of RNG grows, Ontario's access to the RNG market will be limited along with the RNG supply produced within the province. To ensure Ontario customers can participate in this developing market, Enbridge Gas will seek to secure a portfolio of low-carbon energy under agreements that will be of a large enough volume to procure at a reasonable cost. As the pool of RNG is procured, Enbridge Gas will work with large volume customers to encourage their participation in the LCVP.

13. Enbridge Gas expects low-carbon energy commodity purchases will be made on long-term contracts of five years or greater. Accordingly, Enbridge Gas is proposing the cost recovery mechanism be approved for the duration of the low-carbon energy contract term.

14. Enbridge Gas is not requesting pre-approval of specific long-term contracts for commodity purchases consistent with the OEB's Filing Guidelines for the Pre-Approval of Long-term Natural Gas Supply and/or Upstream Transportation Contracts,[3] as the procurement of RNG is not directly supporting new natural gas infrastructure and requesting pre-approval of each RNG contract would be administratively burdensome.

[3] EB-2008-0280.

15. Enbridge Gas's proposal to begin procuring RNG for delivery in 2026, with long-term cost recovery certainty on a long-term basis, will ensure all Enbridge Gas customers have an opportunity to access economic RNG supply being produced within the province and potentially across North America. As demand increases on long-term contracts, access to economic RNG supply will become increasingly challenging. Enbridge Gas's proposal would enable the Company to enter long-term contracts, subject to the maximum bill impact forecast at the time of procurement, without the administrative burden of requesting individual approval for each contract. This proposal would enable recovery of the cost of gas supply commodity purchases for at least the duration of the underpinning commodity contracts.

16. Upon implementation of the LCVP, Enbridge Gas will first offer the low-carbon energy that has been procured to large volume sales service customers on a voluntary basis. Large volume sales service customers will have the ability to voluntarily assume an elected portion of the pass-through commodity costs associated with low-carbon energy as part of the proposed LCVP, up to 100 percent of their actual consumption.

17. Enbridge Gas proposes that the cost of low-carbon energy purchases not recovered through the LCVP be included in the recovery of the cost of gas supply commodity purchases. Enbridge Gas is proposing approval of low-carbon energy purchases to a maximum average residential customer bill impact of $2 per month

per target percentage of low-carbon energy[4], as forecast at the time of procurement. As proposed, the maximum bill impact for an average residential customer would be $8 per month by 2029. Bill impacts for non-residential general service and contract sales service customers will be based on the customers' consumption volumes. The residential customer bill impact will be calculated by taking the cost associated with RNG supply that was not elected as part of the LCVP and including this in the commodity reference price. This approach allows Enbridge Gas the flexibility to contract for low-carbon energy, beginning with RNG, as part of regular business activities.

18. There are two potential situations where Enbridge Gas would stop procuring low-carbon energy for a program year. The first is reaching the target percentage of low-carbon energy in the total gas supply portfolio, and the second is reaching the maximum bill impact for customers, as forecast at the time of purchase. Enbridge Gas estimates that the target percentage of RNG will be able to be procured within the maximum bill impact, however, as market dynamics change, either of these two potential situations may be possible. In a scenario where LCVP demand exceeds the target percentage of low-carbon energy, the Company will, on a best-efforts basis, procure additional RNG to meet this demand on a short-term contract and no additional costs would flow to the gas supply commodity portfolio in that year.

19. The Company will target an increasing level of low-carbon energy purchases, moving from up to one percent of total purchases in 2026 to up to four percent in 2029, capped at a monthly bill impact for each target percentage of low-carbon

[4] For example, one percent of supply would equate to a maximum $2/month average residential customer bill impact and two percent of supply would equate to a maximum $4/month average residential customer bill impact. The monthly consumption of an average residential customer is defined as 200 m^3 in the EGD rate zone (2,400 m^3 annually) and 183 m^3 in the Union rate zones (2,200 m^3 annually).

energy procured. The monthly amount will be based on the forecast gas costs at the time of the low-carbon energy procurement and Enbridge Gas will cap the average residential customer bill impact at $2 per month for each target percentage of the portfolio procured as low-carbon energy, as forecast at the time of purchase. The maximum bill impact will be incremental to the commodity costs charged to customers excluding the low-carbon energy commodity costs. As the FCC increases by $15 per tonne per year from $80 per tonne in 2024 to $140 per tonne in 2028[5], the price differential between conventional natural gas and low-carbon energy will narrow.

20. Enbridge Gas will procure low-carbon energy through a portfolio of low-carbon energy types that the Greenhouse Gas Pollution Pricing Act (GGPPA) recognizes as being exempt from the FCC. Currently, Enbridge Gas plans to use RNG and the associated definition and reduction recognized by the GGPPA.[6] If other low-carbon fuels become recognized as a means to reduce the FCC applicable to consumption, the Company will consider the inclusion of these low-carbon energy alternatives as part of the low-carbon energy procurement in alignment with the gas supply planning principles.

21. Increasing the amount of RNG in gas supply (1) supports an immediate opportunity to reduce GHG emissions within Ontario's building, transportation, industrial and electricity generation sectors; (2) develops an Ontario-based RNG market to supply RNG to the difficult-to-decarbonize sectors such as industrial processes and heavy

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[5] Government of Canada. (2021 August 5). The Federal Carbon Pollution Pricing Benchmark. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information.html

[6] Greenhouse Gas Pollution Pricing Act, September 1, 2022, pp.18-19, https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf

transportation; and (3) provides customers with RNG as an option to achieve GHG emission reduction goals as the energy transition unfolds.

22. An amendment to the GGPPA was published on April 12, 2023, recognizing hydrogen as an FCC exempt fuel.[7] Given this recognition, Enbridge Gas will consider hydrogen procurement in this program when further certainty on the inclusion of hydrogen in the distribution system is available. This will follow the completion of the system-wide Hydrogen Blending Grid Study,[8] discussed at length in Phase 1 of this proceeding. Upon completion of the Hydrogen Blending Grid Study, Enbridge Gas will evaluate the feasibility of including hydrogen within its gas supply commodity portfolio, including the availability of hydrogen supply, pricing, and environmental benefits and may seek approval for hydrogen inclusion as part of a future application.

23. Enbridge Gas will use the existing Gas Supply Plan review process, established from the Framework[9] and subsequent Annual Gas Supply Update proceedings, to provide an overview of LCVP results. At the same time, the Company will also report on low-carbon energy procurement activities, including terms of procurement contracts and forecast bill impacts to customers.

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[7] Government of Canada. (2023 April 12). Regulations Amending Schedule 2 to the Greenhouse Gas Pollution Pricing Act, Amending the Fuel Charge Regulations and Repealing the Part 1 of the Greenhouse Gas Pollution Pricing Act Regulations (Alberta): SOR/2023-62. https://www.gazette.gc.ca/rp-pr/p2/2023/2023-04-12/html/sor-dors62-eng.html
[8] EB-2022-0200, Exhibit 4, Tab 2, Schedule 6, p.16.
[9] EB-2017-0129, Report of the Ontario Energy Board, Framework for the Assessment of Distributor Gas Supply Plans, October 25, 2018.

1.2. Voluntary Program for Large Volume Sales Service Customers

24. To provide the ability for large volume sales service customers to reduce their emissions related to natural gas consumption and the cost associated with the FCC, Enbridge Gas has developed the LCVP for large volume sales service customers. Direct purchase (DP) customers who wish to procure RNG as part of their supply already can arrange this with their supplier as part of their supply arrangement. As a result, Enbridge Gas has developed processes to reduce the FCC on the bill of those DP customers who have attested that their supply is RNG. The proposed LCVP will create a similar ability for sales service customers to reduce their exposure to the FCC.

25. Enbridge Gas is aware of multiple large volume sales service customers who have expressed interest in a more customizable quantity of RNG in their gas supply than is offered through the current VRNG Pilot Program. This customer group interacts frequently with Enbridge Gas and, due to greater gas demands, experiences a greater impact from the FCC.[10] The current VRNG Program does not offer large volume customers access to the volume of RNG supply to achieve the emissions reductions they require. Through existing communication channels with these customers, Enbridge Gas will share the availability of this program without additional marketing spend.

26. With OEB approval, the proposed LCVP will be available to commercial and industrial sales service customers served by contract and large volume general service rate classes. Prior to the proposed implementation of rate class

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[10] Facilities that hold an Exemption Certificate issued by the Canada Revenue Agency (i.e., large industrial facilities registered in Ontario's Emissions Performance Standards Program) are exempt from the FCC on their natural gas bill. Greenhouse Gas Pollution Pricing Act, September 1, 2022, https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf

harmonization, large volume general service customers eligible for the LCVP will be sales service customers with annual consumption greater than 15,000 m^3 in Rate 6 in the EGD rate zone, Rate 01 and Rate 10 in the Union North rate zone, and Rate M1 and Rate M2 in the Union South rate zone. Following rate class harmonization, large volume general service customers eligible for the LCVP will be served as part of the harmonized Rate E02 rate class.

27. The low-carbon energy premium of the LCVP will be recovered through the proposed Rider L which will be effective with the LCVP implementation as provided at Phase 2 Exhibit 8, Tab 2, Schedule 1, Attachment 3.

28. Subject to RNG availability, Enbridge Gas will offer low-carbon energy as part of the LCVP for a commitment period of one year with automatic renewal in subsequent years until a time in which the customer elects a change. This will allow customers certainty on their emissions reductions on a long-term basis. Participating LCVP customers will receive a specified portion of their supply as low-carbon energy and pay the associated premium cost of low-carbon energy above the gas commodity cost through Rider L. The premium will vary based on the portfolio of low-carbon energy the Company procures, however the premium will be known at the time of the commitment by customers to participate and updated to reflect the average price of low-carbon energy procured by Enbridge Gas.

29. Prior to the time of the LCVP offering, Enbridge Gas will contract for the low-carbon energy and communicate the average contract price of the supply as part of the offering. Enbridge Gas will pass through the premium for the selected portion of low-carbon energy to customers who elect the LCVP over the year of the election.

30. Enbridge Gas will reduce the FCC for customers who elect the LCVP on their natural gas bills by a percentage equal to the total annual percentage of low-carbon energy elected by the customer.

1.3. Inclusion of Low-Carbon Energy in Gas Supply Portfolio

31. Low-carbon energy that is not elected as part of the LCVP will be included in the planned gas supply portfolio commodity purchases. These purchases include all supply provided by Enbridge Gas to sales service customers. Enbridge Gas will use the gas supply commodity portfolio forecast of planned purchases, which is updated on an annual basis, to determine the quantity of low-carbon energy to procure.

32. Planned purchases in the gas supply commodity portfolio for 2024 are 527 PJ.[11] Enbridge Gas will plan to procure up to one percent of the equivalent forecast supply requirements as low-carbon energy for 2026 (which includes purchases for system supply, compressor fuel, UFG and own use) and increase target procurement by one percentage point annually until 2029, reaching four percent. Procurement will be executed in alignment with the current gas supply planning principles. Enbridge Gas will seek a diverse, flexible, reliable, and cost-effective supply source of low-carbon energy to meet the target blend percentage.

33. Enbridge Gas will procure this supply to a forecast maximum residential bill impact of $2 per month for each target percentage point of RNG in the gas supply portfolio, after reduction of the FCC, at the time of purchase. This maximum bill impact represents Enbridge Gas's current estimated bill impact for the annual percentage targets assuming no LCVP participation. This approach of establishing a maximum

[11] Phase 2 Exhibit 4, Tab 2, Schedule 1, Attachment 1, p.3, line 8.

bill impact allows Enbridge Gas the flexibility to procure a diverse portfolio of low-carbon energy while providing price certainty to ratepayers as market dynamics for low-carbon energy continue to develop. The rate impacts for other customers will vary based on their forecast consumption.

34. Low-carbon energy costs not recovered through the LCVP will be included in the cost of gas supply commodity purchases, with variances captured in the Purchase Gas Variance Accounts and remain effective for at least the duration of the under-pinning contracts.

35. Enbridge Gas will reduce the FCC for sales service customers to reflect the FCC benefit of the low-carbon energy purchases. Due to timing differences between when the low-carbon energy is delivered into the distribution system and when Enbridge Gas rebates the FCC for that low-carbon energy delivery, variances between actual customer FCCs and actual FCCs collected through rates may arise. These variances will be recorded in the Customer Carbon Charge – Variance Account (CCCVA). On an annual basis, any balance in the CCCVA will be proposed for disposition through the annual Federal Carbon Pricing Program Application. Enbridge Gas will collect and remit the required FCC from customers monthly.

<u>2. Evaluation of Low-Carbon Energy as part of the Gas Supply Commodity Portfolio</u>

36. As discussed in the 2022 Annual Gas Supply Plan Update, the Company determined the need to evaluate the role that low-carbon energy could serve in the gas supply commodity portfolio following supportive customer engagement results specifically for the inclusion of RNG.[12] Through that process, multiple stakeholders

[12] EB-2022-0072, Transcript Day 1, p.91.

showed interest in more information about RNG, with one noting that their members (large commercial customers) are working towards low-carbon operations and net-zero emissions.[13] Stakeholders were seeking more information to be provided via a jurisdictional overview in the rebasing application[14]. As described by VECC, "renewable natural gas has clear benefits to consumers not just in GHG emission reduction but also in potential monetary credits to offset carbon taxes."[15]

37. The Company has undertaken this evaluation, including an assessment of alignment with gas supply guiding principles, a review of lessons learned from the existing Voluntary Renewable Natural Gas (VRNG) Pilot Program, through customer engagement activities and through completion of a jurisdictional overview of the low-carbon energy market. These evaluation components are outlined below.

2.1. Alignment with Gas Supply Guiding Principles and Public Policy

38. The OEB's Framework for the Assessment of Distributor Gas Supply Plans (Framework) set out guiding principles for assessment of natural gas distributors' gas supply plans. It identified three guiding principles used in assessing the plans:

- Cost-effectiveness – The gas supply plan will be cost-effective. Cost-effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner.
- Reliability and security of supply – The gas supply plan will ensure the reliable and secure supply of gas. Reliability and security of supply is achieved by ensuring gas supply to various receipt points

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[13] Ibid, BOMA Submission, May 24, 2022.
[14] Ibid, BOMA, LPMA and VECC Submission, May 24, 2022.
[15] Ibid, VECC Submission, May 24, 2022, paragraph 8.

to meet planned peak day and seasonal gas delivery requirements.

- Public policy – The gas supply plan will be developed to ensure that it supports and is aligned with public policy where appropriate.[16]

39. As outlined below, the proposal to procure low-carbon energy as part of the gas supply commodity portfolio is aligned with each of these guiding principles.

40. Enbridge Gas's proposal to procure low-carbon energy as part of the gas supply commodity portfolio is a cost-effective means to reduce emissions. Low-carbon energy, specifically RNG, is a market-ready solution to advance progress to make meaningful reductions in GHG emissions while leveraging existing infrastructure and assets in a cost-effective manner that does not compromise reliability of supply. Enbridge Gas's proposal to allow large volume system gas customers to voluntarily elect to include RNG in their supply allows customers with emissions reductions goals to meet these goals on a long-term basis. RNG that is not elected for as part of the LCVP will be recovered through the gas commodity reference price. This approach maximizes alignment with customers interests in reducing their emissions, while minimizing the marketing costs required to provide that alignment. It also enables Enbridge Gas the critical ability to contract for RNG supply on a long-term basis, allowing for more economic and reliable access to RNG supply.

41. Government at all levels as well as customers are focused on reducing GHG emissions and transitioning to a low-carbon economy. Specifically, the Ontario government has committed to reducing emissions by 30 percent below 2005 levels by 2030, as outlined in the Made-in-Ontario Environment Plan, which is aiming to

[16] EB-2019-0137, Final OEB Staff Report to the Ontario Energy Board, March 26, 2020.

reduce emissions by 18 Mt of CO_2 by 2030[17]. Enbridge Gas's low-carbon energy proposal is aligned with the spirit of this public policy as it would reduce emissions by over 1.06 Mt of CO_2 by 2029 (assuming four percent of the gas supply commodity portfolio is purchased as RNG). This proposal therefore achieves approximately six percent of the reduction goals in the Made-in-Ontario Environment Plan.

42. In March 2022, the Canadian Biogas Association released a report outlining the role that biogas and RNG could play in meeting Canada's Climate Targets.[18] In its findings, the report states that if new policy were introduced to enact a renewable gas blend mandate and create carbon credits for methane destruction and utilization in landfills and agriculture, biogas and RNG within Ontario could contribute an additional 5.6 Mt of CO_2 emissions reductions by 2030, while also reducing methane emissions by 192 kt at the same time.[19] Additional benefits found in this report include creating 19,900 jobs across Canada and contributing $5 billion in annual GDP.

43. Aligned with the spirit of public policy and cost-effectiveness, and in support of reliable and secure supply, Enbridge Gas is proposing the inclusion of up to four percent low-carbon energy in the gas supply commodity portfolio by 2029.

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[17] Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan, November 29, 2018, p.24, https://prod-environmental-registry.s3.amazonaws.com/2018-11/EnvironmentPlan.pdf
[18] Hitting Canada's Climate Targets with Biogas & RNG, March 2022, https://biogasassociation.ca/images/uploads/documents/2022/resources/Hitting_Targets_with_Biogas_RNG.pdf
[19] Ibid.

2.2. Current Inclusion of Low-Carbon Energy in the Gas Supply Commodity Portfolio

44. To date, Enbridge Gas has incorporated low-carbon energy in the gas supply commodity portfolio through the existing VRNG Pilot Program and phase 1 of the Low Carbon Energy Project (LCEP).

VRNG Pilot Program

45. The existing VRNG Pilot Program was approved by the OEB[20] and implemented in April 2021. This Pilot Program allows customers to voluntarily pay an additional $2 per month towards the inclusion of RNG in the gas supply portfolio. The VRNG Program was proposed and approved as a pilot to provide an opportunity to begin incorporating RNG into the gas supply commodity portfolio.

46. Enbridge Gas procured 1,000 GJ of RNG in March 2022, 2,300 GJ of RNG in February 2023, and an additional 2,300 GJ of RNG in February 2024, based on revenue collected and the forecast of enrolled participants at the time. At the end of Q1 2024, 4,102 customers have enrolled in the VRNG Pilot Program. Enbridge Gas has reduced approximately 278 tonnes of CO_2e through the displacement of conventional natural gas through this program. Enbridge Gas will continue to provide enrollment to the VRNG Pilot Program and will offer this program until the approval and implementation of the low-carbon energy program in this evidence. Following approval of the low-carbon energy program, the Company will use any remaining funds collected from the VRNG Pilot Program to procure RNG for the system supply portfolio as part of the 2026 RNG procurement and discontinue the existing VRNG Pilot Program.

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[20] EB-2020-0066, Decision and Order, September 24, 2020.

47. The VRNG Pilot Program has allowed Enbridge Gas to procure a small volume of RNG on behalf of program participants; however, the ability to purchase the RNG has been limited by lower-than-expected participation in the program. Enbridge Gas has recognized that participation is strongly correlated with marketing campaign spend and timing, with 77 percent of enrollments occurring during active marketing campaigns. For example, Enbridge Gas ran a marketing campaign from March 14 to May 31, 2022, during which a monthly average of 208 participants enrolled in the program, compared to a monthly average of only 59 participants in January and February. Enbridge Gas has attempted to maximize the effectiveness of its marketing budget associated with the VRNG Pilot Program; however, the Company would need to significantly increase and sustain the marketing budget to continue to attract additional customers to this program.

48. The target participants of the existing VRNG Pilot Program are residential and small commercial customers. Through this program, Enbridge Gas has experienced a cost to acquire of $200 per participant. Assuming the cost to acquire a participant remains constant, a marketing budget of $4.8 million for the first two years would be needed to achieve participation levels forecast as part of the VRNG Pilot Program. At this level, RNG procurement would continue to fall short of the demonstrated interest for RNG in customer engagement that was supported by customer engagement results, provided at EB-2022-0200 Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 293 to 295.

Low Carbon Energy Project (LCEP)

49. Phase 1 of the existing LCEP Program began blending hydrogen into the natural gas distribution system in October 2021. Through the LCEP Program, customers have been able to reduce CO_2e by approximately 198 tonnes between October 2021 and February 2024. Further details of this program were provided at EB-2022-

0200 Exhibit 4, Tab 2, Schedule 6. Enbridge Gas will continue to blend hydrogen as part of the LCEP to reduce GHG emissions.

2.3. Customer Support and Engagement

50. Of Ontario's GHG emissions, 32 percent are related to the combustion of natural gas by end-use customers. As noted in Enbridge Gas's customer engagement findings, residential customers ranked "minimizing any impacts on the environment" as a top priority, just behind affordability and the safety and reliability of delivering natural gas as provided at EB-2022-0200 Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 119.

51. Residential and business customers also supported the inclusion of RNG in the gas supply portfolio at an incremental cost. Enbridge Gas asked customers to consider including RNG starting at an additional cost to their current rates. Customer engagement results indicate that 54 percent of residential customers and 52 percent of business customers were supportive of incurring these additional costs to support RNG in the system supply portfolio at various levels.[21] As noted above, this support for Enbridge Gas to purchase RNG is not reflected in the low participation rates of the VRNG Pilot Program, likely due to the requirement of residential customers to take positive action to elect their participation. Small volume customers do not interact frequently with the utility and require considerable Company effort to encourage taking specific actions such as electing to participate in the VRNG Pilot Program. Enbridge Gas's proposal to recover unelected RNG costs through the gas supply commodity portfolio will allow small sales service customers to benefit from the inclusion of RNG without having to take specific

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[21] EB-2020-0200 Exhibit 1, Tab 6, Schedule 1, Attachment 1, p. 32.

action.

52. In addition to support for inclusion of RNG in the gas supply portfolio through the customer engagement process, Enbridge Gas is aware of multiple large volume sales service customers who are seeking to lower their emissions using RNG. Enbridge Gas is in the process of assessing this interest and customer requirements. Many of Enbridge Gas's large volume sales service customers have also set goals to reduce emissions and/or become net-zero. Additionally, municipalities, associations and stakeholders have set ambitious goals to reduce their own and their constituents' emissions. Letters of support for the inclusion of RNG are provided at Attachment 1. Enbridge Gas is aware of customers switching to DP in order to include RNG as part of their gas supply mix, which cannot currently be facilitated through a sales service arrangement. To create a similar opportunity for emissions reductions for large volume sales service, Enbridge Gas is proposing a voluntary program for the inclusion of RNG for large volume sales service customers.

3. RNG Market Overview

53. Enbridge Gas engaged Anew Canada ULC (Anew), formerly Bluesource Canada ULC, to provide a jurisdictional overview (the Anew Report) of the RNG market in North America and the role of RNG for customers seeking to lower the carbon emissions associated with their natural gas supply. The Anew Report is provided at Attachment 2. This report, including the review of RNG programs in other jurisdictions such as those in the provinces of British Columbia (BC) and Québec, has informed Enbridge Gas's proposal for similar inclusion of RNG in its portfolio on both a voluntary basis and through the gas supply commodity portfolio.

54. Since the completion of the Anew Report, the RNG market has continued to evolve across North America. RNG supply has continued to grow, and an increasing number of jurisdictions have enacted regulations to lower GHG emissions of their gas supply by procuring RNG as part of their energy mix. Further, 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 RNG market development. When seeking RNG supply for procurement, buyers have access to supply from across the continent, as they do for conventional natural gas. Enbridge Gas will be able to access this market using both existing upstream portfolio contracts and delivered supplies, as the Company continues to monitor available supply and new market tools and opportunities.

3.1 Supply Developments

55. Rapid development of RNG supply projects in North America has occurred over recent years and is expected to continue, with accelerated short-term growth. From December 2021 to July 2023, the number of North American RNG supply projects that are planned, under construction, or in operation has increased from 446[22] to 781[23] as of July 18, 2023. Figure 1 shows the RNG supply projects spread across North America that are now planned or operational in every continental U.S. state and almost all provinces in Canada.

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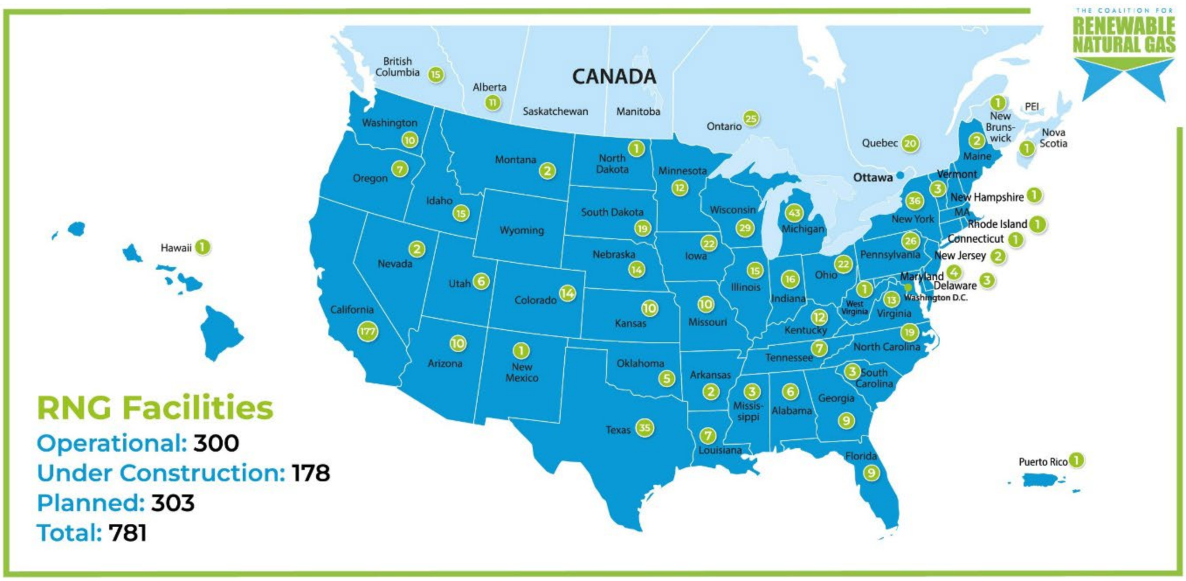
[22] Natural Gas Intelligence. (2021 Oct 28). UGI, Global Common Energy Developing Third RNG Project in Upstate New York. https://www.naturalgasintel.com/ugi-global-common-energy-developing-third-rng-project-in-upstate-new-york/.

[23] The Coalition for Renewable Natural Gas. RNG Renewable Natural Gas Infographics. https://www.rngcoalition.com/infographic

Figure 1: North American RNG Facilities



56. Significant growth in RNG facilities has been experienced in recent years. Wood Mackenzie noted that in 2022, 60 MMcf/d (approximately 0.1 PJ/d) of new RNG production was added, with the number of projects doubling in the last five years.[24]

57. Recent development of RNG projects, some of which is fueled by the U.S. Inflation Reduction Act's Investment Tax Credit, is leading to forecasts of very high near-term growth, followed by continued steady growth until 2050. S&P Global shared one lender outlook, pointing to a 50 percent growth by 2024 and a potential 2.2 Bcf/d (approximately 2.4 PJ/d) by 2050.[25] Existing buyers are benefiting from these

[24] 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/

[25] S&P Global Commodity Insights. (2023 Jan 06). US RNG approaches maturity as lenders eye 50% production growth by 2024. https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/010623-us-rng-approaches-maturity-as-lenders-eye-50-production-growth-by-2024.

rapidly developing near-term supplies and playing a key role in driving development of projects. Many of these buyers, including utilities in Québec and BC are contracting for supply on long-term agreements, accessing supply at competitive prices in comparison to spot market prices. As part of project development, RNG buyers are typically contracting for supply agreements during the planning and construction phases of projects. Access to the RNG market during this expansion in development projects will provide current buyers with more options for supply. Buyers not taking advantage of current opportunities, will lose access to the currently available and developing supply.

58. Enbridge Gas is aware of multiple RNG projects in the planning and construction phase as well as projects in operation. Please see Attachment 3 for supporting documentation from potential RNG suppliers and impacted stakeholders. These documents demonstrate the further development of RNG projects and supply, interest in participating in a competitive bid process should this proposal receive approval, as well as some of the opportunity that RNG provides in both economic development and waste management. Specifically, at page 1 of Attachment 3, one producer states that RNG “presents a remarkable opportunity for rural economic development by promoting the growth of local biogas and agricultural waste-to-energy projects. The development of RNG infrastructure and production facilities can create jobs in rural areas, providing new economic opportunities while also contributing to the diversification of rural economies” Others on page 4, state that Enbridge Gas’s RNG procurement proposal “amplifies market potential for [their] RNG production”. Initial production indications from this group of suppliers point to supply potential of greater than 39 PJ/year.

3.2 Demand Developments

59. RNG demand has continued to increase as both legislated and voluntary buyers contract for supply, typically on a long-term basis. Jurisdictions with legislated RNG targets that increase over time, as well as new jurisdictions entering the RNG marketplace, have contributed to increasing demand. As demand has increased in these areas, the importing and movement of RNG both within and across jurisdictions has become increasingly common and more transparent. In addition, market tools, such as registries for environmental attributes have facilitated greater transparency and efficiency of the RNG market.

60. Multiple utilities have been purchasing renewable natural gas for several years including Énergir, FortisBC and Vermont Gas. Each of these jurisdictions is subject to increasing targets by 2030, as Énergir seeks 10 percent of its supply as RNG to meet legislated targets and FortisBC seeks 15 percent, typically on long-term contracts. These increasing targets, as well as number of utilities entering the RNG market, point to the fact that other jurisdictions are acknowledging RNG will play a role in the energy future. Enbridge Gas needs to begin procuring RNG to take advantage of emerging opportunities to secure supply.

61. More recently, S&P Global has noted that utilities are poised to become bigger players in the RNG market.[26] ONE Gas, which serves 2.2 million customers in Kansas, Oklahoma and Texas[27] has lined up 22 RNG projects and identified 175 Bcf (approximately 194 PJ) of RNG production potential in the states that they

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[26] S&P Global Market Intelligence. (2022 Mar 04). Utilities scale up renewable natural gas purchases, expand project portfolios. https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/utilities-scale-up-renewable-natural-gas-purchases-expand-project-portfolios-69225022
[27] ONE Gas. https://www.onegas.com/home/default.aspx

serve.[28] Puget Sound Energy[29] and Washington Gas[30], both located in Washington State, as well as UGI in Pennsylvania have begun procuring RNG. Florida, Missouri and Minnesota all recently enacted renewable content legislation that will allow RNG to be a viable source of the states' energy mix.[31] These jurisdictions are actively procuring long-term RNG contracts, securing access to RNG for up to 20 years and removing this supply from availability to the market.

62. Currently, utilities and other purchasers of RNG are understood to be importing RNG from across North America to their respective jurisdictions. Énergir, FortisBC and Vermont Gas have all purchased and imported RNG from outside of their jurisdictions.

63. As filed in its 2023-2024 Rate Case, Énergir imports 74 percent of their RNG from outside of their territory. On October 31, 2022, Énergir issued a request for information (RFI) for between 70 to 100 Mm^3 (between approximately 2.7 to 3.9 PJ) of RNG supplies annually, with delivery starting in October 2024. In this RFI, Énergir sought RNG produced anywhere within North America.

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[28] S&P Global Market Intelligence. (2022 Mar 04). Utilities scale up renewable natural gas purchases, expand project portfolios. https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/utilities-scale-up-renewable-natural-gas-purchases-expand-project-portfolios-69225022

[29] Puget Sound Energy. Press Release. (2022 Jun 02) Puget Sound Energy launches Renewable Natural Gas program. https://www.pse.com/en/press-release/details/Puget-Sound-Energy-launches-Renewable-Natural-Gas-program

[30] S&P Global Market Intelligence. (2021 Nov 08). Gas utilities expand renewable natural gas project investments in Q3. https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/gas-utilities-expand-renewable-natural-gas-project-investments-in-q3-67492573

[31] S&P Global Market Intelligence. (2021 Aug 09). Gas utilities plot RNG expansion as supply chain issues emerge. https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/gas-utilities-plot-rng-expansion-as-supply-chain-issues-emerge-65964095

64. As of 2021, FortisBC indicated that it expected to import 74 percent of its RNG supply from across North America, of which 18 percent is expected to be supplied from Ontario.[32] The Government of British Columbia has identified RNG as a viable low-carbon energy source. FortisBC currently purchases and imports RNG from at least two Ontario producers, Faromor CNG and Stormfisher.[33] It is entering into long term agreements (up to 20 years) with producers and, in some cases, purchasing supply before production has started.

65. As filed in its Gas Supply and Renewable Natural Gas Report July 1, 2022, Vermont Gas is entering into long-term RNG supply deals with producers across North America.[34] These producers include The Dubuque Water and Resource Recovery Center in Dubuque, Iowa, BP on behalf of London RNG, Vanguard Renewables and Archaea Energy Marketing LLC. This approach to procurement further supports the fact that RNG can be sourced from across North America and is not limited to the jurisdiction in which a utility operates.

66. Similar to Énergir, FortisBC and Vermont Gas, Enbridge Gas also has the ability to purchase RNG produced outside of Ontario in the same manner that it procures conventional natural gas produced outside of Ontario and is therefore not limited to Ontario RNG supplies. Enbridge Gas may purchase RNG outside of Ontario due to factors including supply availability, price and diversification. This supply can be

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[32] 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
[33] Ibid, page 74.
[34] Vermont Public Utility Commission, July 2023 Annual Supply Plan, June 30,2023.
https://epuc.vermont.gov/?q=node/64/190881/FV-ALLOTDOX-PTL

accessed both through the upstream transportation portfolio and through delivered supplies.

67. Large end-users of natural gas have also recognized RNG can reduce their carbon footprint[35] and began procuring based on long-term contracts. Specifically, AstraZeneca recently announced a partnership with Vanguard Renewables to annually procure 650,000 MMBtu (0.7 PJ) of RNG, powering operations across North America.[36]

68. As this supply develops, key market tools and efficiencies to facilitate transactions, leading to further transparency, have also been progressing. Platts Gas Daily began publishing a daily spot market price for RNG on May 16, 2023, with the aim of bringing further transparency to the emerging market.[37] As the market continues to develop, advancements such as these will lead to further ease of transacting and access to supply for buyers.

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[35] S&P Global Commodity Insights. (2022 Dec 16). RNG industry expects US voluntary customers to spur demand after early transport boom. https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/121622-rng-industry-expects-us-voluntary-customers-to-spur-demand-after-early-transport-boom

[36] AstraZeneca. (2023 Jun 13). AstraZeneca announces innovative partnership with Vanguard Renewables to decarbonize its United States sites. https://www.astrazeneca-us.com/media/press-releases/2023/astrazeneca-announces-innovative-partnership-with-vanguard-renewables-to-decarbonize-its-united-states-sites.html

[37] Yahoo Finance. (2023 May 16). Platts of S&P Global Commodity Insights Launches First-of-Type Daily Price Assessments for North America Renewable Natural Gas. https://finance.yahoo.com/news/platts-p-global-commodity-insights-120000209.html?guce_referrer=aHR0cHM6Ly93d3cuYmluZy5jb20v&guce_referrer_sig=AQAAAI-WhcUkd6Kyat9irRwFEBONx0rOa3qHAP0qmnZf227AqLYFdbqtWMzd3HgQVdm_hlOJVZIAaQ9ASKEOMpkez9iYnsOCnMyxUqewVBIuvvf206iWamcuWZp4G9fuhptnIcfVeMom6etXHMSaNrt1hH3cJzdlG8Q47K8ulRTjkgP5&guccounter=2

4. GHG Emissions Reporting and Reductions from RNG

69. This section of evidence provides details regarding how RNG achieves emissions reductions and how these RNG-related emissions reductions are recognized within existing government policies and regulations, as well as being disclosed through Enbridge Gas's GHG emissions reporting.

70. Enbridge Gas complies with all applicable federal and provincial climate policies. These policies recognize RNG as a low-carbon fuel and provide direction on how the Company quantifies and claims environmental attributes and/or emissions reductions associated with RNG under each government regulated program.

71. GHG emissions related to the combustion of natural gas by end-use customers are subject to the GGPPA. The GGPPA requires Enbridge Gas to apply the FCC on the natural gas it distributes to applicable customers. The GGPPA does not apply the FCC to RNG and, therefore, has inherently recognized RNG as being free of CO_2 emissions. As such, the GGPPA recognizes that RNG, when displacing a conventional natural gas molecule, avoids the CO_2 emissions associated with the combustion of a natural gas molecule. This is also supported by the federal and provincial GHG reporting programs and Ontario's Emissions Performance Standard (EPS), all of which allow reporters to subtract the CO_2 emissions from combustion of RNG from their reportable GHG emissions.

72. This GHG emission avoidance is equivalent to 0.05[38] tonnes of carbon dioxide equivalent per gigajoule (tCO_2e/GJ) of RNG. It is important to note that although 0.05 tCO_2e/GJ is emitted when a GJ of either conventional natural gas or RNG is burned, these emissions are considered avoided when RNG (also known as biomethane) is burned. This is because RNG is produced from decomposing organic matter (e.g., food waste, human and animal wastes) which is ultimately derived from plants that utilize and remove carbon dioxide (CO_2) from the atmosphere; therefore, the CO_2 emitted from combusting RNG is part of the short-term natural carbon cycle and not a net increase in GHG emissions.[39] This is aligned with the reduction recognized in the GGPPA:

> **Natural gas that contains biomethane**
>
> **(7)** Unless subsection (8) applies, if a quantity of marketable natural gas or non-marketable natural gas contains a particular proportion of biomethane (expressed as a percentage), for the purpose of this Part, the quantity of marketable natural gas or non-marketable natural gas is deemed to be the number of cubic metres determined by the formula
>
> $\mathbf{A \times (100\% - B)}$
>
> where

---

[38] The emission factor for natural gas in Ontario can be calculated from the Ontario Marketable Natural Gas charge of $0.0979/cubic meter (Greenhouse Gas Pollution Pricing Act, September 1, 2022, Table 4, pp.242-245, https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf), divided by 2022 carbon price of $50/t CO_2e (Government of Canada. (2021 August 5). The federal carbon pollution pricing benchmark. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information.html) and equals 0.001958 tCO_2e/cubic meter.
Using Enbridge Gas's average annual heat content for 2021 of 0.03884 GJ/standard m^3, the emission factor in energy units is 0.05041 tCO_2e/GJ.

[39] Report Update: Biomethane Greenhouse Gas Emissions Review, March 31, 2017, https://www.cdn.fortisbc.com/libraries/docs/default-source/services-documents/offsetters-biomethane_greenhouse_gas_emissions_reviewe6fecb594de843768ae02951f4b8d3eb.pdf?sfvrsn=821688c4_2

A is the number of cubic metres that the marketable natural gas or non-marketable natural gas would occupy at 15°C and 101.325 kPa; and

B is the particular proportion.[40]

73. The GGPPA allows for the proportion of any RNG contained in the natural gas supply to be subtracted from the total volume reported and subjected to the FCC. The FCC is based on the emission factor for marketable natural gas and represents direct emissions released from the combustion of natural gas and is not based on a lifecycle carbon intensity (CI) approach. Biomethane (i.e. RNG) as provided in the GGPPA is described as "a substance that is derived entirely from biological matter available on a renewable or recurring basis and that is primarily methane"[41] and does not differentiate the various feedstocks or methods of RNG production nor the various carbon intensities or indirect upstream emission reductions that may arise. As a result, replacing one GJ of conventional natural gas with one GJ of RNG regardless of the lifecycle CI associated with the supply procured achieves a full reduction in the applicable FCC for ratepayers.

74. On a lifecycle basis, RNG can provide two separate and distinct emission reduction benefits. These benefits are discussed in detail at Phase 1 Exhibit J4.3:
    1. Upstream and indirect emissions reduced from the production source.
    2. Direct emissions reduced through displacing combustion of conventional natural gas.

[40] Greenhouse Gas Pollution Pricing Act, September 1, 2022, pp.18-19, https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf
[41] Ibid, p.5.

75. As discussed above, since RNG is produced from biogenic sources, the CO_2 released to the atmosphere during its combustion is not considered incremental. The capture of methane that would have otherwise been released to the atmosphere (from the decomposition of organic wastes) is an additional emission reduction benefit that is associated with the production of RNG,[42] and distinct from the benefit experienced when combusting RNG. Where the avoided methane emissions are eligible to be included in the calculation of RNG lifecycle carbon intensity, the resulting CI is often a negative value.[43]

76. The Company acknowledges the lifecycle emission benefits of using RNG; however, at this time, the CI score of RNG will not be the primary consideration when procuring RNG.

77. The CI of procured RNG (and hydrogen, pending the results of the Hydrogen Blending Grid Study) becomes an important consideration when it influences the number of credits that may be generated under the Clean Fuel Regulations (CFR). CFR credits created from the production of RNG or hydrogen may be sold to primary suppliers (i.e., obligated parties) where the sale of the CFR credit represents a means of lowering the procurement cost of RNG or hydrogen. As noted, Enbridge Gas has no obligation under the CFR (i.e. is not a primary supplier); however, it may participate in the CFR on a voluntary basis. CFR credits are new regulatory instruments that were introduced with the publication of the CFR as of July 6, 2022, and can be created by eligible low-carbon fuels that displace

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[42] Clean Fuel Regulations: Specification for Fuel LCA Model CI Calculations, July 2022, p.120, https://data-donnees.az.ec.gc.ca/api/file?path=/regulatee%2Fclimateoutreach%2Fcarbon-intensity-calculations-for-the-clean-fuel-regulations%2Fen%2FArchive%2FCFR-Specifications-for-Fuel-LCA-Model-CI-Calculations-v1.0.pdf
[43] Some observed CI values for RNG are presented at Phase 1 Exhibit J4.1

natural gas use, as is the case with the Enbridge Gas proposed procurement. A lower CI score will produce more credits per GJ of RNG or hydrogen than a higher CI score, relative to the reference carbon intensity for gaseous fuels as defined in the CFR.[44]

78. The Company has not determined at this time if RNG will be purchased with or without CFR credits. If Enbridge Gas purchases RNG with CFR credits, it envisions that the benefits, less expenses, generated from CFR credit sales will reduce the incremental cost of low-carbon fuel. The means by which RNG-related CFR credit costs and revenues will be treated are described in the Phase 1 Settlement Agreement.[45] As part of the Phase 1 Settlement Agreement, the parties agreed to the creation of a new Clean Fuel Regulation Credits Deferral Account that will record the revenues obtained by Enbridge Gas from the sale of CFR credits and certain offsetting costs. Enbridge Gas may elect to procure RNG without CFR credits, where it is forecast that procurement of RNG without the CFR credit leads to more cost-effective procurement. The nascence of the CFR and its credit market means that there is currently credit price uncertainty.

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[44] Canada Gazette Part II, Vol. 156, No. 14, Clean Fuel Regulations, July 6, 2022, Schedule 1, p.2790, https://www.canadagazette.gc.ca/rp-pr/p2/2022/2022-07-06/pdf/g2-15614.pdf

[45] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 2, Accounting Orders - Phase 1, Accounting Order Number 179-330, August 17, 2023, p.47.

Federation of Rental-housing Providers of Ontario

20 Upjohn Rd., Suite 105
Toronto ON M3B 2V9
416-385-1100
1-877-688-1960
www.frpo.org

Tony Irwin
President & CEO

t: (416) 385-1100 ext. 20
e: tirwin@frpo.org

October 2, 2023

To whom it may concern,

The Federation of Rental-housing Providers of Ontario (“FRPO”) supports Enbridge’s application for approval of a low-carbon energy procurement.

FRPO represents more than 2,200 members who own or manage over 350,000 households in Ontario. As an industry, we recognize that we have a significant carbon footprint, not only with the construction of new supply, but also in our daily operations. We understand our need to reduce fossil fuel consumption; however, alternatives to fossil fuels remain limited.

FRPO believes that Renewable Natural Gas (RNG), created from the anaerobic digestion of organic materials, has a significant role to play in helping us reduce our reliance on fossil fuels and smooth the transition to renewable sources of energy. Currently, Ontario does not have the infrastructure or technology to support the transition to full use of renewable energy. RNG is a great option to act as a bridge between fossil fuels and renewable resources, allowing time for that infrastructure to be built and the technology to be developed.

As Ontario works to transition to renewable energy, there needs to be major changes across all industries. The rental housing industry recognizes our responsibility to be a part of the solution and help influence our peers and tenants across Canada so that we can achieve these goals.

Enbridge’s procurement of RNG could provide rental housing providers across Ontario with a way to reduce their consumption of fossil fuels and supply quality RNG to the markets where they operate. The Federation of Rental-housing Providers of Ontario would be interested in supporting Enbridge’s development of an RNG program which meets the interests of both its members and the people of Ontario.

Sincerely,

Tony Irwin
President & CEO

SKYLINE

September 28, 2023

To whom it may concern,

Skyline Group of Companies ("Skyline") supports Enbridge's application for approval of a low-carbon energy procurement.

Skyline Group of Companies ("Skyline"), a fully integrated asset acquisition, management, development, and investment entity, is comprised of multiple Funds and Businesses that span the apartment, industrial, and retail real estate industries. Environmental stewardship has long been an integral part of Skyline's business vision and is a key factor in decision-making at every level of our operations.

As a major player in Canada's real estate industries and owner of hundreds of properties across Canada, we know that we are a significant contributor to fossil fuel consumption. As part of our overarching sustainability plan, we have taken steps to improve efficiencies at our properties and reduce our use of fossil fuels where we can. This includes massive lighting retrofits, installing hundreds of EV chargers and dozens of rooftop solar systems at our properties, endless boiler and heating system upgrades, and the list goes on. However, when it comes to solutions beyond implementing new technologies and finding efficiencies, the options are limited. Canada does not currently have the infrastructure or technology required to fully transition our assets to renewable energy.

Skyline believes that Enbridge's procurement of Renewable Natural Gas (RNG) is a viable solution to help companies like ours reduce fossil fuel consumption and act as a bridge while renewable energy infrastructure and technology are developed.

As Canada works to transition to renewable energy, there needs to be major changes across all industries. We recognize that we have a responsibility to be a part of the solution and help influence our peers, and tenants, across Canada to make sustainable decisions. As such, Skyline would welcome the option of RNG as a fuel source.

Jason Ashdown
Co-Founder, CSO
Skyline Group

5 Douglas Street, Suite 301 • Guelph, ON • N1H 2S8 • Ph: (519) 826-0439 • Fax: (519) 836-2320 • SkylineGroupOfCompanies.ca

September 26, 2022

Nicole Brunner
Technical Manager, New Energy Supply
Enbridge Gas Inc.

Dear Ms Brunner:

RE: Support for the proposed Enbridge Gas Low Carbon Voluntary Program

The City of Burlington owns a significant inventory of municipal facilities (ie. administrative, operations and recreational) and, therefore, is a large consumer of natural gas. Burlington City Council has approved a target for city operations to be net carbon neutral by 2040 and community wide by 2050. In 2019, City Council declared a climate emergency.

Renewable Natural Gas (RNG), being carbon neutral, and also exempt from the Carbon Charge, is one way to lower GHG emissions affordably. We understand that Enbridge Gas is looking to evolve its current RNG program to encourage more customers to consume greater quantities of low carbon energy by making it easier to participate.

We understand that the proposed program would offer large volume sales service customers an annual option to voluntarily sign up to receive customizable quantities of RNG and other types of low carbon energy. We support Enbridge Gas procuring RNG via long term contracts to gain access to reliable RNG at the lowest possible cost, given the premium price of short term RNG. This will also have the benefit of supporting RNG developments, jobs, and investments in Ontario.

We further understand that to the extent the large volume sales service customers do not elect to voluntarily sign up, in aggregate, for the full quantities of RNG contracted by Enbridge Gas on a long-term basis, that the excess RNG, including its benefits and incremental costs would be allocated to all sales service customers.

These complimentary inclusions of RNG in the Enbridge Gas gas supply portfolio allow large sales service customers to easily obtain the RNG quantities they desire to help meet their GHG reductions goals at more affordable prices. At the same time, all system sales service customers will also have access to RNG.

We are interested in how this program can help us reduce our emissions and achieve our reduction targets noted above. Climate change is a global issue with significant local impacts, as we are seeing warmer, wetter and wilder weather in our community.

We support Enbridge Gas' efforts to invest in and expand the RNG program to assist the City in its efforts to reduce its carbon footprint.

Sincerely,

Allan Magi, P.Eng.,
Executive Director, Environment, Infrastructure and
Community Services

cc: Lynn Robichaud, Manager of Environmental Sustainability
City of Burlington

London
CANADA

300 Dufferin Avenue
P.O. Box 5035
London, ON
N6A 4L9

September 26, 2022

Nicole Brunner
Technical Manager, New Energy Supply
Enbridge Gas Inc.
Via: Nicole.Brunner@enbridge.com

Re: Municipal Support Letter – Proposed Enbridge Gas Low Carbon Voluntary Program

On behalf of the Corporation of the City of London, we are pleased to express support for Enbridge Gas' proposal for their Low Carbon Voluntary Program. The proposal is consistent with the directions of Municipal Council with respect to actions to address climate change as per London's Climate Emergency Action Plan.

We understand that Enbridge Gas is looking to evolve its current renewable natural gas (RNG) program to encourage more customers to consume greater quantities of low carbon energy by making it easier to participate. Specifically, the proposed program would offer large volume customers the option to voluntarily sign up to receive specific quantities of RNG and other types of low carbon energy (e.g., hydrogen), with surplus RNG being allocated to the system gas used by smaller volume customers.

The City of London is committed to learn more and will consider this action as we move forward with implementation of our compressed natural gas fueled waste collection vehicles as well as explore options for landfill gas utilization.

Thank you for the opportunity to participate in this important project proposal. Please do not hesitate to contact Jay Stanford if you require further details (519-661-2489, ext. 5411 or jstanfor@london.ca).

Sincerely,

Kelly Scherr, P.Eng., M.B.A., F.E.C.
Deputy City Manager
Environment & Infrastructure

Jay Stanford, M.A., M.P.A.
Director, Climate Change, Environment &
Waste Management

Tibbar Services Inc.
690 Fountain St N
Cambridge, ON, NH3 4R7

Attention: Nicole Brunner, Technical Manager
New Energy Supply

September 30th, 2022

RE: Support for the proposed Enbridge gas Low Carbon Voluntary Program

Tibbar Services Inc (TSI) is 'for hire' truck fleet located in Cambridge Ontario was established in 2013. As a fleet owner and a master diesel mechanic I have adopted natural gas technology because of the lower cost of fuel and the simpler maintenance schedule of CNG trucks help me run a profitable enterprise. Natural gas has been a good hedge in a volatile diesel market.

TSI now owns and operates seven CNG branded trucks. Our company logo celebrates the connection to natural gas with a rabbit that "emits" methane as a visual cue to prospective customers. The intent of the TSI logo is to drive communication about the favourable environmental aspects of transportation with natural gas.

A greater availability of Renewable Natural Gas (RNG) would position my company and other like minded CNG fleet owners to respond for demand from shippers who wish to demonstrate lower emissions through their inbound and outbound supply chains.

Therefore, I support a voluntary program for Renewable Natural Gas for these reasons:

- Brand Alignment – TSI is positioned as a provider of transportation services with a lower impact on the environment. Easy access to RNG gives empowers my company to differentiate from mass market carriers,

- CNG Stations – presently my suppliers of CNG include Hiller Truck Tech (HTT) and Clean Energy (CE). They have indicated that procuring RNG is administratively challenging, and,

- NRCan Green Freight Program – HTT, CE and others have indicated that incentives for natural gas trucks will be contingent on the running the trucks on some amount of RNG. Any policies that promote the availability of RNG will help TSI and other CNG fleets to successfully participate in Federal market transformation programs.

Sincerely,

B. Wigle
President and Owner, Tibbar Services Inc.
Cell 519.505.7963
brian.tibbar@yahoo.com

RURAL GREEN ENERGY INC.

440 Wright Boulevard, Unit #2,
Stratford, ON, N4Z 1H3
519-625-8025
Email: info@ruralgreenenergy.ca

September 28th, 2022

To: Enbridge Gas Inc.

Attention: Nicole Brunner, Technical Manger
New Energy Supply

RE: Support for the proposed Enbridge gas Low Carbon Voluntary Program

Our company located in Oxford County Ontario was established in 2015 with the objective of delivering RNG fuel produced on rural Ontario farms to the transportation industry. At the time we realized that no market existed in the province which encouraged a financial incentive for fleet owners to adopt gas engine technology in lieu of traditional diesel engines. We had to rely solely on savings in fuel costs of CNG vs diesel to persuade fleets to adopt. Although adoption in the USA continued to progress, particularly in California, where government incentivized pricing remained an encouragement for low carbon fuel sources displacing diesel as the preferred transportation fuel. Over the past seven years many engine innovations have encouraged this trend and disastrous weather events globally have reinforced the need to decarbonize our current fossil energy supply source.

We believe that renewable natural gas offers governments and industry a better opportunity short term (next 15-20 years) to reduce our global dependency on traditional fossil derived gas. It resolves our societal need to recycle & reuse waste products in an increasingly circular economy while diminishing carbon emissions. It can be accomplished using existing pipeline & fuelling infrastructure for distribution that is far reaching for both fuelling heavy duty trucks and serving pipeline located industrial, commercial & home users. The same infrastructure, within limits, can play a role in the gathering of rural production gas and making it available to all these remote consumers as well.

Currently, we contract our rural production RNG gas to Fortis B.C. an out of province utility offering us an opportunity to develop Ontario based rural farm renewable gas production sites under long term fixed contracts. This is needed to permit our investor supported project activity & continued growth of rural gas production sites throughout the province. It would be advantageous to us to engage in similar future contracts with Enbridge such that the carbon credits remain within Ontario assisting the province to achieve its greenhouse gas mitigation commitments.
In addition our supplied RNG into the Enbridge gas portfolio give them the RNG quantities needed to be able to provide both small volume and/or large volume users to voluntarily participate towards achieving GHG reduction goals/targets.

In conclusion this proposed RNG program offering by Enbridge would impact us positively as our success is dependent upon increased number of production sites of RNG throughout rural Ontario and encouragement towards adoption of transportation fleets to consider alternate low carbon fuels.

K. Wayne Blenkhorn, P. Eng., CEO
CNG/RNG Rural Green Energy Inc
Cell 519-404-7866
wayne@ruralgreenenergy.ca

October 6, 2022

Attention:
Nicole Brunner
Technical Manager, New Energy Supply
Enbridge Gas Inc.
Via: Nicole.Brunner@enbridge.com

Subject: Support for the proposed Enbridge Gas Low Carbon Voluntary Program

Canada Bread Company, Limited (doing business as Bimbo Canada) hereby states:

Grupo Bimbo is the world's largest baking company, whose purpose is to build a sustainable, highly productive, and deeply humane company. The company operates in 32 countries throughout the Americas, Europe, Asia and Africa, and encompasses many familiar brands, including Oroweat, Bimbo, Tia Rosa, Sara Lee and more. Bimbo Canada is a subsidiary of Grupo Bimbo.

Grupo Bimbo announced in November 2021 its commitment to achieve Net Zero Carbon emissions by 2050. This commitment considers emissions for its entire value chain, covering all Scopes across all activities. By doing this, Grupo Bimbo has become the first Mexican food company to commit to Business Ambition for 1.5°C and join the United Nation's Race to Zero Campaign with targets established and validated by Science Based Targets. More urgently, Grupo Bimbo has committed to a 50% reduction in Scope 1 emissions by 2030.

Renewable Natural Gas (RNG) is one way to lower GHG emissions affordably. We understand that Enbridge Gas is looking to evolve its current RNG program to encourage more customers to consume greater quantities of low carbon energy by making it easier to participate.

Bimbo Canada shares the belief that an innovative project to promote the use of RNG should be developed in Ontario to derive economic and environmental benefits of a low-emission energy vector and which Bimbo Canada could participate in as a consumer in the future.

Sincerely,

Canada Bread Company, Limited

DocuSigned by:
A Lee
9B2774715A034DD...

By: ________________________
Name: Alice Lee
Title: VP Legal

06 October 2022 | 10:04:56 AM CDT

HILLER
TRUCK TECH Inc.

Saving Fuel and the Environment

Attention: Nicole Brunner, Technical Manager
New Energy Supply

October 3rd, 2022

RE: Support for the proposed Enbridge gas Low Carbon Voluntary Program

Hiller Truck Tech Inc (HTT) is truck repair and CNG fitment facility located near Cambridge Ontario was established in 2004. As a diesel mechanic I have introduced natural gas technology to my customers because of favourable environmental impact of these trucks relative to Diesel Trucks.

The consistently lower cost of fuel and maintenance is attractive to HTT's customer fleets. To support our customers HTT now owns and maintains a fleet of over twenty Class 8 CNG trucks under a rent-to-own program with Enbridge. These trucks travel from the Windsor Ontario in SW Ontario, through to Ottawa in Eastern Ontario, North to Sudbury, and South to Fort Erie. HTT owns a CNG station to facilitate fuel access. Increasingly, my customer fleet are asking about access to Renewable Natural Gas (RNG) from the HTT and other stations. My early research has shown that commercial access to RNG is anything but easy in Ontario.

A greater availability of Renewable Natural Gas (RNG) would enable HTT and HTT's associated CNG fleet clients to respond for demand from corporate customers shippers who seek to lower their GHG emissions.

As such, strongly supports a voluntary program for Renewable Natural Gas.

Best Regards,

David Hiller
President, Hiller Truck Tech Inc.
Cell (519) 635-3675
david@hillertrucktech.com

Enbridge Gas Inc.

North American Renewable Natural Gas Market Evaluation

September 2022

Prepared by:

anew

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Conditions of Use

This overview titled "North American Renewable Natural Gas Market Evaluation" was prepared for Enbridge Gas Inc. (including any documents attached hereto or incorporated herein). This analysis represents Anew's good-faith effort to provide an objective and accurate summary of current and anticipated future market conditions, based on Anew's long-standing and extensive experience in such markets and third-party observations and data. Market conditions can change, however, at any time, and may (and likely will) be affected by multiple factors outside of Anew's control. Anew expressly disclaims any obligation to update this analysis.

Anew believes that all information in this market analysis is accurate. However, Anew has, in some cases, relied on information obtained from third parties in preparing this analysis and makes no warranty as to the completeness or accuracy of information obtained from such third parties, nor can it accept responsibility for errors of such third parties, appearing in this analysis.

Executive Summary:

Enbridge Gas Inc (Enbridge Gas) is the largest regulated local distribution company (LDC) in North America by volume. Enbridge Gas engaged Blue Source Canada ULC (now Anew Canada ULC, "Anew") to evaluate the role of green gas for customers seeking to decarbonize their gas supply and to provide a jurisdictional overview of the renewable natural gas (RNG) market in North America. Anew focused on analyzing RNG availability and current voluntary or mandated compliance programs in North America jurisdictions.

Anew Advisory defines RNG as being derived from biomass or other renewable resources and is a pipeline-quality gas that is fully interchangeable with conventional natural gas.

Given the above, our key findings include:

- **Supply:** North America RNG production has grown substantially over the last decade and should continue to expand given forecasts of ample (nearly 44,000) project site inventories, feedstock potentials, and investment interest.[1] Each producing project has unique capital investment requirements, costs for processing and operations, RNG yields, and resultant lifecycle carbon intensity (CI). As more fully cited later in the body of this report, forecasters expect that North American RNG supply, led by carbon negative RNG, could substantially decarbonize gas consumption. Based on current project site inventories as noted above and the average reference output volumes developed by independent analysts (as developed later in this document, Table 5.1.1), the RNG produced across the inventory of U.S. project sites could decarbonize as much as 48% of current North American natural gas demand. Other potential projects involve the thermal gasification of woody residue and other waste biologic feedstocks. These technologies are being demonstrated for feedstocks that are difficult for anaerobic digestors to process. Other potential projects may come about by utilizing power to produce gas via electrolysis and methanization. These technologies, although considered pre-commercial today, will develop over time with support and bring more RNG supply into the market.
- **Demand:** The primary drivers of North American RNG demand are U.S. Federal and California state compliance programs mandating roadway fuel decarbonization. North American transportation market demand for RNG in 2025 could absorb nearly 370,000 dekatherms (Dth) per day according to the latest estimates by the RNG Coalition.[2] RNG is also in demand for renewable power generation, building and process heat. Other jurisdictions, including Canada, are instituting green programs in the transportation and gas utility sector. Corporate and household voluntary efforts are also increasing North American RNG demand. RNG's ability to be flexibly used across the continent for fuel or feed stock with low or negative CI drives the demand. Some forecasters expect RNG to fully supplant geologic gas use as economical RNG supplies expand and as efficiency and electrification limit gas demand growth overall.
- **Market Pricing and Structure:** The highest price for North American pipeline-delivered RNG is typically set by "stacked" or summed values for RNG. In Canada, stacked values for RNG can be realized by recognizing the avoided tax under the federal Greenhouse Gas Pollution Prevention Act and other potential value-adding programs like the B.C. Low Carbon Fuel Standard (LCFS). The

[1] RNG Coalition SMART Initiative Plan to Utilize Methane Capture — The Coalition For Renewable Natural Gas

[2] Provided by RNG Coalition, from within their commissioned study, "Renewable Natural Gas: Transportation Demand Supplemental Estimates", April 29, 2022, by Bates & White Economic Consultants, as restated by conversion factor of 1 ethanol gallon equivalent to 0.0853 Dekatherms.

highest values that RNG can achieve today come from stacking the California's LCFS and the U.S. Federal Renewable Fuels Standard program. Not all RNG production qualifies for stacked pricing, and RNG prices also vary with rarity, production costs, market accessibility, and decarbonization potency. Negative CI RNG commands the highest prices and therefore remains attractive to produce despite generally higher operating and capital costs. Broad market access is enabled by extensive North American pipeline infrastructure. That, along with book and claim mechanics assure that stacked prices typically hold, except for small tariff basis deductions, for continental buyers and sellers of similar quality RNG. RNG can be procured by voluntary and compliance buyers via direct or intermediated counterparty transactions or on the transparent M-RETs exchange that allows digital trading of RNG one dekatherm at a time.

- **Jurisdictional Program Reviews:** Several major natural gas utilities in North America have implemented 'green' tariff programs for residential and commercial customers. These programs are a mix of mandatory and voluntary to participants and are offered on a cost recovery basis with set prices per block to offset natural gas and/or greenhouse gas emissions. Some programs offer a combination of RNG and carbon offsets (5% and 95% respectively) to achieve emission reductions. Marketing costs can be a large percentage of the program costs for these voluntary programs, potentially reducing the spend that could have been used to achieve further RNG procurement. Some of the mandatory programs have been successful based on their ability to secure long term contracts with suppliers at prices lower than the spot market.

1.0 Introduction

Enbridge Gas Inc. (Enbridge Gas) is in the process of submitting an application for rate rebasing with the Ontario Energy Board (OEB). As part of this application Enbridge Gas is proposing to evolve their current Voluntary RNG (VRNG) pilot program. As a result, Enbridge Gas seeks to better understand the challenges and opportunities of RNG as well as the approach that utilities in other jurisdictions have taken, to inform their proposed RNG program to the OEB.

Bluesource Canada, ULC[3] (now Anew Canada, ULC. [Anew]) was retained by Enbridge Gas to perform a jurisdictional overview of the RNG market in North America and identify and discuss how other large-scale utilities use green energy products. The scope of work included the following:

- a jurisdictional overview of the renewable natural gas market in North America;
- a scan of North American utilities who currently use green energy products as part of their gas supply portfolio to reduce the emissions of their customers on a voluntary and non-voluntary basis;

The following research report addresses the above scope of work for North American RNG markets.

1.1 Background

In the November 2018 Made-in-Ontario Environment Plan, the Ontario Government indicated its plans to meet Ontario's 2030 emission reduction target, including increased use of clean fuels such as RNG. The Government also highlighted its goal of increasing access to clean and affordable energy for families. Taking these items into account, the Made-in-Ontario Environment Plan[4] required natural gas utilities to implement a voluntary RNG option for customers.[5]

In 2021, the OEB approved Enbridge Gas's application[6] to implement a voluntary pilot RNG program that provides interested customers with the opportunity to pay a $2 monthly charge enabling Enbridge Gas to purchase RNG as part of the company's overall gas supply. The amount of RNG procured depends on the number of participants in the program, the availability of RNG, as well as the cost difference between RNG and conventional natural gas. The incremental cost of RNG above the cost of conventional natural gas supply is funded entirely by program participants, with no direct costs for RNG procured assigned to non-participants.

The biggest challenge of the current program is the limited volume of RNG that Enbridge Gas can procure based on program participation that restricts Enbridge Gas from securing long-term contracts at lower rates. This inability to secure long-term contracts does not future proof the program or allow for scalability should a renewable fuel mandate be implemented in the future requiring utilities to incorporate a set goal of RNG into their supply. As determined by the OEB during the previous application, Enbridge Gas cannot

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[3] Bluesource ULC was contracted by Enbridge Gas Inc. in May, 2022. As of July 4, 2022, Blue Source Canada, ULC (**Bluesource**) merged with Element Markets, LLC (**Element**), another developer of carbon and environmental credits, to form a combined entity now called Anew Climate, LLC ("**Anew**"), which is under majority ownership by TPG Rise and TPG Rise Climate, global impact investing platforms managed by alternative asset firm TPG. Anew Canada, ULC is a Canadian subsidiary of Anew Climate, LLC.

[4] Government of Ontario, 2018. Preserving and Protecting our Environment for Future Generations: A Made in Ontario Environment Plan. Ministry of the Environment, Conservation and Parks. 2018. See page 33. https://www.ontario.ca/page/made-in-ontario-environment-plan

[5] Direct Purchase customers have the option to procure RNG. Enbridge Gas introduced the 2021 voluntary program to enable RNG access for system supplied customers.

[6] Ontario Energy Board, 2020. Decision on Order on Cost Awards, EB-2020-0066: Voluntary Renewable Gas Program Application. October 29, 2020. https://www.rds.oeb.ca/CMWebDrawer/Record?q=casenumber:EB-2020-0066&sortBy=recRegisteredOn-&pageSize=400#form1

have non-participating customers bear any costs of the program. Therefore, current procurement of RNG is in the secondary market once sufficient revenue has been collected from the participants to secure a tranche of supply.

Enbridge Gas is evaluating the role of RNG in its portfolio and is seeking a scalable program that aligns with customer interest in RNG while working towards lowering its greenhouse gas (GHG) footprint. Enbridge Gas completed customer engagement, filed in the Annual Gas Supply Update, that demonstrated both general service residential and business customers are supportive of paying a premium for RNG as part of their gas supply.[7]

2.0 Regulations Supporting RNG Development

A number of federal, provincial, and state policies, regulations, and programs have had a significant role in shaping the current RNG market in Canada and the U.S. RNG is sensitive to government policy because traditionally, climate solutions have not had an intrinsic market value[8]. This means that RNG has been less cost competitive against its traditional fossil-fuel equivalents because its significant climate advantage and benefits have not been reflected in the price. Government policies at the federal, provincial and state levels are helping to correct this market failure. Policy incentives along with more project development and potential technological improvement will likely shrink the prevailing but likely durable price premium of RNG relative to conventional natural gas. A summary of these initiatives is provided below.

2.1 Canada

Greenhouse Gas Pollution Pricing Act

The Greenhouse Gas Pollution Pricing Act[9] (GGPPA) is a Canadian federal law establishing a set of minimum national standards for carbon pricing in Canada to meet emission reduction targets under the Paris Agreement. The aim of the legislation is to put a price on all greenhouse gases through binding "minimum national standards" on the federal government and all of the provinces and territories. The standards on pricing are divided into two parts: Part 1 is a regulatory charge on carbon-based fuels[10] and Part 2 is an output-based emissions trading system for polluting industries[11] (Output Based Pricing System [OBPS]).

Part 1 of GGPPA establishes a fuel charge, which is a regulatory charge on fossil fuels. It is generally paid by fuel producers and fuel distributors in backstop jurisdictions.[12] The fuel charge applies to 21 fossil fuels including gasoline, light fuel oil (such as diesel), and natural gas. It also applies to combustible waste, which includes tires and asphalt shingles. The fuel charge rates reflect a carbon pollution price of $30 per

[7] EB-2022-0072, EGI Submission, Appendix A
[8] Canadian Biogas Association, 2022. Hitting Canada's Climate Targets with Biogas and RNG. https://biogasassociation.ca/images/uploads/documents/2022/resources/Hitting_Targets_with_Biogas_RNG.pdf
[9] Greenhouse Gas Pollution Pricing Act, S.C., 2018, C12., S.186. https://laws.justice.gc.ca/eng/acts/G-11.55/FullText.html
[10] Greenhouse Gas Pollution Pricing Act, S.C., 2018, C12., S.186, Part 1, https://laws-lois.justice.gc.ca/eng/acts/G-11.55/page-1.html#h-244007
[11] Greenhouse Gas Pollution Pricing Act, S.C., 2018, C12., S.186, Part 2 https://laws-lois.justice.gc.ca/eng/acts/G-11.55/page-18.html#h-246320
[12] Backstop jurisdictions are those provinces or territories in which the provincial or territorial regulations do not meet the federal benchmark for carbon pricing, and therefore the federal regulations prevail. British Columbia, Quebec, Nova Scotia, Northwest Territories, New Brunswick, and Newfoundland and Labrador implemented their own carbon pollution pricing systems that meet the federal benchmark for both the OBPS and fuel charge. The remaining provinces and territories are subject to the federal backstop pricing for one or both of these benchmarks.

tonne of carbon dioxide equivalent (CO_2e) as of April 1, 2020 rising by $10 per tonne annually to $50 per tonne as of April 1, 2022.[13]

RNG is exempt from the carbon charge as it is not a fossil fuel. The GGPPA does not consider the carbon intensity of a fossil fuel or fossil fuel replacement, such as RNG, in its calculation of the carbon fuel charge. Under the GGPPA, RNG is valued volumetrically for its ability to displace natural gas and the emissions associated with its combustion on a 1:1 basis. This is different than the Clean Fuel Regulations, as noted below, which does account for the carbon intensity of a fuel. Since the GGPPA does not consider carbon intensity, the ability to prevent the release of methane to the atmosphere from various types of RNG (e.g., anaerobic digesters that receive manure or other organic wastes) goes unrecognized and unmonetized.

Clean Fuel Regulations (CFR)

The Federal Clean Fuel Regulations (CFR)[14] was finalized and released in June 2022, where the compliance obligation for covered entities (liquid fuel producers) begins in July 2023. The purpose of the CFR is to lower the carbon intensity (CI) of fuels produced and consumed in Canada. The CFR allows covered entities a variety of means to achieve compliance. Fuels with CI above the regulatory target will generate deficits, whereas low CI fuels will generate credits, and obligated parties must purchase credits or pay into a compliance fund to cover their total deficits. RNG is applicable to two compliance categories: category 2 which increases supply of renewable and low CI fuels, and category 3 is for specified end-use fuel switching in transportation. RNG can create credits even when those fuels are not used in transportation. Category 2 would apply for credit creation under the gaseous class and would be subject to the 10% usage limit. Here, the credit creator would be the producer or importer of the RNG. Credit creation would be based on the CI of the RNG as compared to the reference CI for the gaseous class.[13] RNG used as fuel for a vehicle in Canada could create compliance credits under category 3 for fuel switching applications. Here, the credit creators would be the producer/importer of the fuel and the owner/operator of a fueling station.[13]

Credits can be bought and sold between registered creators and primary suppliers directly for an agreed upon price. The price of credits in the Credit Clearing Mechanism, which is used when obligated parties that have not been able to acquire credit elsewhere and still have a deficit need to acquire credits, has a maximum of approximately $300 CAD/CFR credit of CO_2e.[15] The Compliance Fund Mechanism within the CFR can be used to satisfy a maximum of 10% of the reduction requirements for a given compliance period. Upon contribution to a fund, a primary supplier would receive credits that are non-tradable and non-bankable. The price to create a credit from the CFM is $350 CAD/CFR credit (2022)[14]. A primary supplier would be authorized to carry forward up to 10% of its reduction requirements at 20% annual interest rate, only if there were not sufficient credits in the Credit Clearance Mechanism to satisfy its deficit and it has used its maximum contribution to an emission reduction fund.[14]

Low Carbon Fuel Standards (LCFS)

Clean fuel regulations require fossil fuel suppliers to gradually reduce the carbon intensity of their fuels while allowing for a range of compliance pathways to help them achieve their targets. One permitted tool

[13] https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/greenhouse-gas-annual-report-2020.html
[14] *Clean Fuel Regulations* SOR/2022-140, https://www.canadagazette.gc.ca/rp-pr/p2/2022/2022-07-06/html/sor-dors140-eng.html
[15] *Clean Fuel Regulations* SOR/2022-140, https://www.canadagazette.gc.ca/rp-pr/p2/2022/2022-07-06/html/sor-dors140-eng.html

is the integration of cleaner fuel alternatives. As a result, depending on how the programs are designed, clean fuel standards can stimulate RNG activity.

British Columbia's (B.C.) Low Carbon Fuel Standard[16], initially introduced in 2008, aims to achieve a 20 percent reduction in the carbon intensity of transportation fuels by 2030. In 2019, RNG was approved for inclusion as a transportation fuel, which sends a positive signal to RNG developers, though confined to its use for transportation. Average credit prices in the B.C. LCFS, have almost doubled since compliance year 2020 with average credit pricing as of July 2022 at \$444.85/tCO_2e[17] For reference, there are two CNG projects (CI scores equals 6.81 gCO_2e/MJ and 10.02 gCO_2e/MJ) listed in the approved carbon intensities table for transportation fuel producers who wish to have a fuel carbon intensity approved for posting and use in British Columbia.[18] At the listed CI scores and average July 2022 cost per credit value, the value per GJ of these projects would be approximately \$3.02 to \$4.46/GJ.

Renewable Gas Mandates

Renewable fuel mandates require fossil fuel suppliers to blend in a minimum percentage of renewable content. This type of regulation has existed at the federal and provincial levels for liquid fuels since 2011. More recently, it has been used at the provincial level for gaseous fuels, with B.C. and Québec both using mandates to require that provincial natural gas suppliers add renewable content to their supplies of conventional natural gas. This in turn has stimulated the adoption of RNG alongside other renewable gases[1].

- British Columbia: B.C.'s emerging renewable gas mandate will require natural gas suppliers to blend at least 15 percent renewable content by 2030.[19]
- Québec: Québec's RNG mandate, implemented in 2019, aims to achieve a five percent renewable blend by 2025 and 10 percent renewable blend by 2030.[20]

In B.C., the BCUC has approved long-term supply agreements (e.g., 10 years) for purchases of RNG by the utility. These long-term purchase agreements are not backstopped by long-term sales agreements. The agreements for RNG supply from out of province as also been approved by the BCUC. Pricing for such supply agreements for up to \$31/GJ (with a 2% annual increase) is approved by the BCUC. Pricing is somewhat related to CI scores, with lower CI score projects attracting higher prices.[21]

Organic Diversion and Landfill Controls

Many provincial governments have regulations governing methane emissions from landfills. Because landfill gas is a major feedstock for RNG energy, these regulations can stimulate RNG development. However, the impact of these regulations is limited by the fact that compliance can often be met through

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16 *Renewable and Low Carbon Fuel Requirements Regulation*, B.C. Reg. 394/2008. https://www.bclaws.gov.bc.ca/civix/document/id/crbc/crbc/394_2008

17 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/monthly_credit_market_report_-_2022-07.pdf

18 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf012_-_approved_carbon_intensities_-_current_-_20220815_v2.pdf

19 Government of British Columbia, 2018. CleanBC: Our nature, our power, our future. See page 66. https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_2018-bc-climate-strategy.pdf

20 Government of Quebec, 2020. 2030 Plan for a Green Economy: Framework policy on electrification and the fight against climate change. See page 84. https://cdn-contenu.quebec.ca/cdn-contenu/adm/min/environnement/publications-adm/plan-economie-verte/plan-economie-verte-2030-en.pdf?1635262991#:~:text=With%20the%202030%20Plan%20for,require%20substantial%20effort%20from%20everyone.

21 https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/102_2012

simple methane collection and flaring, without utilization through biogas and RNG energy. It should also be noted that where regulation requires landfill gas destruction, projects will not be eligible to create offsets and carbon intensity calculations would not recognize the avoided methane from an activity that is required.

- British Columbia: Large landfills producing over 1000 tonnes of methane per year are required to collect landfill gas and flare.[22]
- Manitoba: Three largest landfills are required to collect landfill gas.[23]
- Ontario: Landfills larger than 1.5 million cubic metres of waste disposal capacity are required to collect landfill gas and to flare it or to use it.[24]
- Québec: Large landfills collecting more than 50,000 tonnes of residual materials per year are required to collect landfill gas and to flare it or utilize it.[25]

Offset Systems

Government-regulated GHG offset systems allow credits to be generated by approved activities that voluntarily reduce emissions. These credits can then be sold to firms to help them comply with regulated emissions reduction targets. Offset systems that allow credits to be generated through methane destruction in the waste or agriculture sectors can be effective at stimulating biogas and RNG development so long as they allow utilization through biogas and RNG as an eligible destruction device.[26]

Federal: The Canadian Greenhouse Gas Offset Credit system regulations currently enables project proponents to generate federal offset credits using the Landfill Methane Recovery and Destruction protocol.[27] The protocol allows for either the destruction of landfill gas or the injection of upgraded landfill gas into a natural gas network.

Alberta: The Alberta Emission Offset System allows credits to be generated by biogas and RNG projects – including landfill gas, diverted organic waste, animal manure and wastewater projects – and sold to firms regulated under the TIER (Technology Innovation and Emissions Reduction) regulation.[28]

Québec: Firms regulated under the province's cap-and-trade system can purchase offsets, including through landfill and manure-based biogas and RNG projects.[29]

Under Development: Offset protocols are currently under development by governments in B.C. and Saskatchewan.

[22] Landfill Gas Management Regulation B.C. Reg 391/2008, https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/391_2008#section7

[23] Canadian Biogas Association, 2022. Hitting Canada's Climate Targets with Biogas and RNG. https://biogasassociation.ca/images/uploads/documents/2022/resources/Hitting_Targets_with_Biogas_RNG.pdf

[24] *Landfilling Sites* OR232/98, Part III, Section 15. https://www.ontario.ca/laws/regulation/980232

[25] Regulation respecting the landfilling and incineration of residual materials Q-2, R19, https://www.legisquebec.gouv.qc.ca/en/document/cr/Q-2,%20r.%2019%20/?langCont=fr#se:32

[26] Canadian Biogas Association, 2022. Hitting Canada's Climate Targets with Biogas and RNG. https://biogasassociation.ca/images/uploads/documents/2022/resources/Hitting_Targets_with_Biogas_RNG.pdf

[27] Government of Canada, 2022. Federal Offset Protocol: Landfill Methane Recovery and Destruction, V1.0. https://publications.gc.ca/collections/collection_2022/eccc/En4-461-2022-eng.pdf

[28] Environment and Parks Alberta, 2020. Quantification Protocol for Biogas Production and Combustion. Government of Alberta, https://open.alberta.ca/dataset/e4dadabf-2c60-4cba-8182-2d1f5e360e86/resource/32eba277-cb6d-4615-90c1-86c7f264c63c/download/aep-quantification-protocol-for-biogas-production-and-combustion.pdf

[29] Gouvernement du Québec, 2011. Regulation respecting a cap-and-trade system for greenhouse gas emission allowances, Appendix D – Offset Protocols, https://www.environnement.gouv.qc.ca/changements/carbone/credits-compensatoires/index-en.htm

Canadian Policy Considerations

The CFR is a low-carbon fuel standard type program that, while aiming to lower the carbon intensity of liquid fossil fuels, recognizes the use of low carbon fuels in other applications. The CFR is unique in this aspect, as RNG used to displace natural gas used to heat buildings or to produce power has the ability to create CFR credits that regulated entities can use for compliance. To date, existing low-carbon fuel standard programs only create credits where low-carbon fuels are used in transportation.

In B.C. and Québec, renewable gas content mandates are volumetric and recognize the direct GHG emission reduction benefits of RNG, but do not consider the indirect GHG emission reduction benefits (i.e., take a lifecycle approach that recognizes avoided biogenic methane releases, also known as carbon intensity [CI] of the gas) provided from RNG. The Federal Greenhouse Gas Pollution Pricing Act[30] and the Québec cap and trade system[31] considers RNG in a similar fashion, where the GHG emission reduction benefits reflect only the direct emission reductions and do not vary according to the type of RNG or the indirect GHG emission reductions benefits that are expressed by carbon intensity values.

In Canadian jurisdictions with RNG mandates, the introduction of the CFR should create an additional value stream where the CFR credits from RNG use can be sold to CFR regulated entities (i.e., liquid fuel producers) and CFR credit revenues can lower the effective RNG price. In this context, the carbon intensity of RNG will affect credit creation and revenue potential, where the lower the CI the more CFR credits and revenue can be created, however the carbon intensity of the RNG will have no influence on the direct emission reductions, as recognized in the GGPPA, or achieving the volumetric mandates.

2.2 United States (U.S.)

U.S. policy and RNG markets are more developed than the Canadian markets to date. The data from these markets can be useful for predicting the development of the Canadian market.

Renewable Fuel Standard (RFS)

The RFS[32] is a federal U.S. policy that mandates the blending of biofuels with transportation fuels. An obligated party's requirement, known as Renewable Volume Obligation (RVO), is tracked by the Environmental Protection Agency (EPA) through a tradable credit system known as Renewable Identification Numbers (RIN). Obligated parties must return a certain number of RINs, based on their RVO, to the EPA to prove compliance with the annual standard at the end of the compliance year. The statutory volumes under the RFS are set to expire at the end of 2022, giving the EPA authority to set biofuel blending requirements post-2022 unless new statutory volumes are established through the legislative process. Some members of Congress have voiced support for the replacement of the RFS with a national LCFS program (like California's) that provides incentives for a wider-range of low-carbon fuels (e.g., hydrogen, electricity, biofuels, etc.). There appears to be support for the continuation of the RFS in some form, but

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[30] *Greenhouse Gas Pollution Pricing Act*, S.C. 2018, C12., S186. https://laws-lois.justice.gc.ca/eng/acts/g-11.55/

[31] Regulation respecting a cap-and-trade system for greenhouse gas emission allowance, C. Q-2, r. 46.1. https://www.legisquebec.gouv.qc.ca/en/document/cr/Q-2,%20r.%2046.1

[32] 40 CFR Part 80: Regulation of Fuels and Fuel Additives, Subparts K and M https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-80?toc=1

failure to create new statutory volumes after 2022 may introduce uncertainty into RIN markets[33]. Current RIN values as of June 2022 ranged from $1.35 USD for D6 fuel to $3.24 USD for D3 fuel ($1.73-4.14 CAD).[34]

California Low Carbon Fuel Standard

The California Air Resources Board (CARB) approved the LCFS[35] program in 2009, which was designed to reduce the CI of California's transportation fuels by 10% by 2020. The LCFS has been amended and extended to a target of a 20% reduction in CI by 2030. The standard puts a price on carbon in California, with low-carbon fuels generating credits for their carbon reduction, and higher-carbon fuels generating a deficit. A build-out of electrification and other low-carbon technologies also generates credits[36]. Like the Canadian systems, CI scores are key to the LCFS. Current LCFS credit values as of June 2022 ranged from $78 USD to $202 USD per credit ($100-258 CAD), with the average price approximately $113 USD per credit ($144 CAD).[37] This is down from an average high in 2020 of $199 USD per credit ($254 CAD).[38]

The California LCFS market is the most established market to date for RNG. Several other markets are starting to emerge including the Washington Clean Fuel Standard[39] and the Oregon Clean Fuel Standard.[40] In January 2022, the Oregon Department of Environmental Quality (DEQ) announced that it was conducting a rulemaking to propose changes to the Clean Fuels Program regulation. The proposed rulemaking may include expansion of the annual average carbon intensity reduction targets beyond 10% and beyond 2025; modifications to the program that will support achievement of the new standards; and other modifications to improve the effectiveness of the Clean Fuels Program.[41]

The Washington Clean Fuel Standard includes a mandate for a 20% reduction in the carbon intensity of transportation fuels from 2017 levels by 2038 and may begin as early as January 2023.[42]

Midwest Low Carbon Policy

Midwestern Governors Association advisory group on low carbon fuel policy issued a 2010 report[43] recommending a regional approach as a next best alternative to a comprehensive federal policy. The report recommended a 10 % reduction in 10 years. No Midwest state has adopted a LCFS in response.[44]

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[33] Per. Comm. 2022. Faizal Hassan, Director Environmental Products, Anew Climate. June 22, 2022.

[34] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information

[35] Assembly Bill 32. Chapter 488, (California, 2009) http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf ,and Executive Order S-01-07, http://gov.ca.gov/executive-order/5172/

[36] RBC ESG 2020 report

[37] Monthly LCFS Credit Transfer Activity Report for June 2022. https://ww2.arb.ca.gov/sites/default/files/2022-07/June%202022%20-%20Monthly%20Credit%20Transfer%20Activity_0.pdf

[38] Monthly LCFS Credit Transfer Activity Report for December 2020. https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/credit/December%202020%20-%20Monthly%20Credit%20Transfer%20Activity.pdf

[39] Transportation Fuel -Clean Fuels Program Chpt 70A.535, https://app.leg.wa.gov/RCW/default.aspx?cite=70A.535

[40] Oregon Clean Fuels program, OAR Chpt 340, division 253, https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=1560

[41] https://www.oregon.gov/deq/rulemaking/Pages/cfp2022.aspx

[42] Canadian Biogas Association, 2022. Hitting Canada's Climate Targets with Biogas and RNG. https://biogasassociation.ca/images/uploads/documents/2022/resources/Hitting_Targets_with_Biogas_RNG.pdf

[43] LCFS Working Group, 2010. Midwestern Low Carbon Fuel Standard Working Group Final Recommendations https://secureservercdn.net/166.62.108.196/8jk.4e3.myftpupload.com/wp-content/uploads/Events/LCFP/FinalRecommendations.pdf

[44] https://www.rngcoalition.com/policies-legislation-1

Northeast/Mid-Atlantic Clean Fuels Standard

Governors of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont signed a 2009 memorandum of understanding committing to develop a regional low carbon fuel standard.[45] All states have adopted laws to achieve 80% reduction from 1990 levels of GHG emissions. A regional LCFS has not been adopted. Efforts continue with policy support from Northeast States for Coordinated Air Use Management.

Regional Greenhouse Gas Initiatives (RGGI)

RGGI was established in 2005 and operates as a regional cap-and-trade program for CO_2 emissions from power plants. Electricity generating units with a nameplate capacity over 25 MW (15 MW in New York) are required to comply with the cap and procure CO_2 allowances or offsets. Agricultural manure management (RNG production) and landfill methane capture are two qualifying project activities that provide CO_2 offset allowances based on avoided methane emissions. While CO_2 allowance prices have risen in recent months due to increased speculative activity (from $8 USD in Q2 2021 to $13.50 USD in July 2022 [46]), historically low prices coupled with the requirement that projects must be located in a RGGI state has resulted in only limited interest in offset development. Members of the RGGI include Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Virginia, and Vermont.[47] Pennsylvania also has a RGGI rule in place, but linkage with the program is delayed due to court cases.

Renewable Gas Mandates

In February 2022, the California Public Utilities Commission (CPUC) announced a renewable gas mandate that applies to California's four major natural gas distributors as well as its many smaller ones.[48] The California mandate is specific to biogas-sourced RNG, as opposed to hydrogen or biomethanized RNG, and requires a 12.2% minimum renewable blend of the utility's own share of 2020 annual bundled core customer natural gas demand by 2030. Dairy methane is limited to 4% of the medium-term procurement obligation. The Commission's Energy Division will process individual contracts to procure biomethane through a three-tier advice letter approval process: Tier 1 for contract prices up to $17.70 USD/MMBtu; Tier 2 for contract prices between $17.70 and $26 USD/MMBtu[49]; and Tier 3 for contract prices above $26 USD/MMBtu.[49] A modified GHG, Regulated Emissions and Energy Use in Technologies (GREET) model will be used to determine CI scores of proposed projects. Utilities are directed to report CI scores in their advice letters to the CPUC seeking approval of a procurement contract. The CI score for purposes of procurement will be used for contract review and procurement decisions. However, the CI score can change as production facilities change; thus, ongoing CI score management will be subject to review.[50]

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[45] Northeast and Mid-Atlantic Low Carbon Fuel Standard Memorandum of Understanding, 2009. https://www.nescaum.org/documents/lcfs-mou-govs-final.pdf/https://www.nescaum.org/documents/lcfs-mou-govs-final.pdf/

[46] Market Monitor Reports. https://www.rggi.org/auctions/market-monitor-reports

[47] https://www.rggi.org/program-overview-and-design/elements

[48] Senate Bill 1440 (California, 2022), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M454/K335/454335009.PDF

[49] 1 MMBTU equals 1 Dekatherm

[50] CPUC, 2022. Decision Implementing Senate Bill SB1440, Biomethane Procurement Program. Rulemaking 13-02-008 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M454/K335/454335009.PDF

Renewable Portfolio Standards (RPS)

A RPS is a law that requires retail electricity suppliers to generate a minimum percentage of their electricity using eligible renewable energy sources. Twenty-nine (29) States and the District of Columbia have mandatory RPS laws. Seven States have non-binding goals. No two RPS laws are the same. A typical law includes a percentage and a date to be met. For example, the Renewable Portfolio Standard in California requires municipal and investor-owned utilities to generate 60% of their energy from renewable sources by 2030.[51] Interim annual targets are required with three-year compliance periods and 65% of RPS procurement is to be derived from long-term contracts of 10 years or more. RPS mandates are often backed by penalties for non-compliance and statutorily limit the impact on the consumer's rate (most below 10%, 13 States below 5%).[52] Generating electricity from renewable sources like RNG helps states meet their RPS policy goals of ensuring stable, diversified energy portfolios that are not overly dependent on fossil fuels.

[51] Renewable Portfolio Standards Program
https://www.cpuc.ca.gov/rps/#:~:text=California's%20RPS%20program%20was%20established,a%2050%25%20RPS%20by%202030.
[52] https://www.eia.gov/energyexplained/renewable-sources/portfolio-standards.php

3.0 Existing Green Energy Programs

The desire to decarbonize by industry, commercial entities and residential consumers has given rise to demand for RNG across North America. Aside from the regulatory-driven and mandatory compliance markets, the voluntary market for RNG is also broadening and expanding.

In some cases, larger industrial firms invest in RNG production plants or arrange counterparty purchases from producers and wholesale marketers. Larger commercial entities often do likewise. For example, Shell Oil Products U.S., a subsidiary of Royal Dutch Shell plc., has successfully achieved the start up and production of RNG at its biomethane facility in Oregon.[53] Residential consumers are also increasingly able to access RNG supplies via their local gas distribution utilities.

The demand-pull at the residential and commercial levels for RNG supply is like earlier demand pull and adoption by these same customer groups for renewable electric power. Some customer groups are also seeking to voluntarily purchase carbon offsets to advance their decarbonization ambitions beyond renewable electricity or RNG.

Marketers and utilities are devising product packages that afford opportunities for customers to purchase these environmental assets and are useful for decarbonization across North America. Anew has undertaken a survey of these utility programs which is presented from publicly available sources surveyed in the table provided in Appendix A. The highlights of these programs have been summarized below.

3.1 Program Highlights

Program size: Of the top 15 largest residential distributors in the U.S., with populations served between 745,000 and 5.5 million, and distributed natural gas volumes between 54 PJ and 242 PJ[54], six companies have RNG programs in place and/or have recently proposed programs. The majority of the remaining companies within the top 15 make some mention of using RNG and/or are actively pursuing procurement of RNG, but do not have residential and/or commercial programs in place. In Canada, gas utilities with RNG programs in place include Enbridge Gas, FortisBC, and Énergir. Other residential gas distributors such as APEX Utilities, Medicine Hat, or SaskEnergy, do not currently offer RNG to residents. Both SaskEnergy and APEX Utilities have indicated they are exploring ways to provide RNG to customers.[55,56]

Many of the companies that have voluntary RNG programs have much smaller residential and/or commercial gas volumes than Enbridge Gas (e.g., Vermont Gas, Black Hills Energy, NW Natural, Puget Sound etc.[57]) and the ability to secure larger percentages of their total natural gas demand is simplified due to these smaller required volumes. For example, Vermont Gas has 4.1 billion cubic feet (bcf) per year (4.3 PJ) in residential distribution with approximately 46,400 residents.[58] It was aiming to achieve 25,000 Mcf (0.3 PJ) of RNG, or 7% of residential natural gas demand in 2020.[59]

[53] https://www.shell.us/media/2021-media-releases/shell-starts-production-at-shell-new-energies-junction-city-its-first-us-renewable-natural-gas-facility.html
[54] https://www.aga.org/contentassets/d68b868b7cd94ed2889b704b441ab469/1002resvol.pdf
[55] https://online.flippingbook.com/view/782040202/28/
[56] https://www.apexutilities.ca/safety-sustainability/hydrogen-renewable-natural-gas/
[57] https://www.aga.org/contentassets/d68b868b7cd94ed2889b704b441ab469/1002resvol.pdf
[58] Vermont Gas is the only natural gas distribution company in the State. https://www.aga.org/policy/state/natural-gas-state-profiles/VT/
[59] Vermont Department of Public Service, 2021. 2021 Annual Energy Report: A summary of progress made toward the goals of Vermont's Comprehensive Energy Plan, Pg 34
https://legislature.vermont.gov/Documents/2022/WorkGroups/Senate%20Natural%20Resources/Reports%20and%20Resources/W~Ed%20McNamara%20~Annual%20Energy%20Report%202021%20DPS~1-15-2021.pdf

Voluntary or mandatory: Of the programs surveyed, there is a mix of both voluntary and mandatory use of RNG. Where there is mandatory use of RNG due to renewable portfolio standards or renewable gas mandates in place, some utilities are also providing voluntary programs to residential consumers in addition to the mandatory incorporation of RNG to the system (e.g., FortisBC). Based on a review of program applications, it appears that voluntary programs are generally proposed over mandatory programs. These programs allow customers the choice in the dollar amounts they want to pay for the service.

The proposed FortisBC program is a combination of voluntary and mandatory.[60] The proposed program provides mandatory delivery of 100% RNG to all new residential dwellings. Customers will pay a low carbon gas charge equal to the combination of the commodity cost recovery charge plus carbon tax - which is the equivalent rate as other gas customers. Another mandatory aspect of this program is the Renewable Gas Blend for sales customers under which all customers who purchase gas from FortisBC will be provided a base level of RNG as part of their regular gas service, subject to supply. FortisBC expects to begin this as a 1% blend on January 1, 2024. The blend will increase over time to enable the company to meet the provincial GHG emissions targets. FortisBC also has an existing voluntary program offering customers the option to purchase up to 100% RNG to meet GHG emission reduction targets. This helps customers that need to reduce their GHG emissions to meet internal or externally imposed targets. This combination of voluntary and mandatory programs enables long-term contracting for RNG and achieving a larger percentage of RNG into the system than a voluntary program on its own. The inclusion of a voluntary component allows those customers that have GHG reduction goals to increase their purchase of RNG beyond the mandatory volumes provided by the utility.

Optionality: In the voluntary green programs being offered, program delivery is generally a similar structure across utilities where customers are given the option of a fixed dollar amount or a fixed percentage of RNG that offsets a portion of their monthly natural gas use with RNG (e.g., 1% to 100% of their natural gas use replaced with RNG[61], or $10 per month for RNG[62], see Appendix A), or customers can pick the dollar amount and equivalent percentage of GHG emissions reductions they would like to pay for (e.g., $4 per month that may offset 25% of their natural gas emissions[63], see Appendix A). Some programs give a single price for the program and others give a range of prices the customer can chose from. For example, Enbridge Gas charges a single price of $2 per month for their RNG program[64] versus Puget Sound Energy where customers can start at $5 per month and pay as much as they would like to incorporate RNG[65]. The average lower end price for programs is approximately $5 per month, although the associated quantities of RNG that this translated into for each program differed depending on how their program costs are calculated and the price paid for RNG. For example, Dominion Energy has $5 blocks that equate

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[60] FortisBC, 2021. Letter to BCUC, re: Biomethane Energy Recovery Charge (BERC) Rate Assessment Report -BCUC Order G-35-21 https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf

[61] Gazifère website: https://gazifere.com/en/renewable-natural-gas/#:~:text=Gazif%C3%A8re%20is%20proud%20to%20present,sites%20and%20water%20treatment%20plants.

[62] CPUC, 2020. Decision Adopting Voluntary Pilot Renewable Natural Gas Tariff Program. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M349/K624/349624040.PDF

[63] DTE Website: https://solutions.dteenergy.com/dte/en/Products/DTE-CleanVision-Natural-Gas-Balance-LVL-1/p/NATURAL_GAS_BALANCE_LEVEL_1

[64] Enbridge Gas Website: https://www.enbridgegas.com/sustainability/optup

[65] Puget Sound Energy Website: https://www.pse.com/green-options/Renewable-Energy-Programs/Renewable-Natural-Gas-Business

to 0.5 therms per month of natural gas use that is replaced with RNG[66], Avista Energy has $5 blocks that equate to 1.5 therms per month of natural gas use[67], and Blackhills Energy has $5 blocks that equate to 20.5 therms per month of natural gas use. Most often these programs do not require the physical delivery of RNG in the pipeline. The utilities will purchase the green environmental attribute associated with the RNG that is required. Therefore, the 'block' that is being purchased is the cost for delivery of a specified quantity of environmental attributes for RNG, equivalent to the amount of natural gas that would have been purchased.

Type of green energy procured: Several of the utilities use a combination of RNG and carbon offsets in their program offering for zero carbon natural gas. The mix of RNG to offsets is largely at 5% RNG and 95% offsets, although in a few cases utilities are using or trialing 10% and 90% or 1% and 99%, or 100% offsets. Some notable programs that use RNG only are the SoCal Gas program and the FortisBC program. In most cases where a combination of RNG and offsets are being used, the RNG is being supplied through contracts with marketers who carry a portfolio of RNG directly with RNG producers. In most cases the physical delivery of the RNG is not a requirement, and so the environmental attribute of the RNG is purchased through book and claim type systems. The M-RETS program for tracking and verifying the renewable thermal credit associated with the RNG was proposed and/or is used in several programs to provide transparency and credibility to the environmental attribute. The transparency and verification of RNG is an element that appeared to be important to several of the commissions when evaluating the RNG program applications.[68] Although physical delivery was not a requirement in most programs, there was a desire to support local sources of RNG where possible which was encouraged by commissions as part of their program approvals.[69]

Where the information is available publicly, the carbon offsets are purchased from one of the four main voluntary carbon registries including Verra's Verified Carbon Standard (VCS), Gold Standard, Climate Action Reserve (CAR), and/or American Climate Registry (ACR). These are considered reputable registries that provide real, verifiable, enforceable, permanent, and additional carbon projects. Some utilities explicitly indicate a preference for offset projects that are locally sourced from nature-based projects, while others highlighted their financial support for projects in developing countries with their offset purchase. Transparency regarding where the projects are located and how they are tracked and verified is a common theme to many of the programs as this helps to ensure that stakeholders are adequately informed as to where their funds were going.

Carbon intensity of RNG is generally not a characteristic that is discussed in the green energy program applications. If the program is being done for voluntary carbon reduction purposes, GHG accounting through the World Resources Institute (WRI) GHG Protocol would allow for the RNG to be accounted for as zero carbon emissions (depending on the gas type). If the gas is considered to have a negative carbon intensity, this may be accounted as avoided emissions in the inventory.[70]

[66] Dominion Energy website: https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/utah/greentherm/2020-annual-greentherm-program-report-6-30-2021.pdf?la=en&rev=cecbe954c6174f6791313e8ee96daeee
[67] Avista Energy website: https://www.myavista.com/energy-savings/green-options/renewable-natural-gas#:~:text=Avista's%20RNG%20program%20supports%20RNG,purify%20it%20to%20make%20RNG.&text=Check%20out%20our%20FAQs%20to,program%20and%20its%20many%20benefits.
[68] https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_790732,
[69] https://epuc.vermont.gov/?q=node/104/16215/FV-Legacy-EXHDOX-PTL
[70] https://ghgprotocol.org/sites/default/files/standards/Product-Life-Cycle-Accounting-Reporting-Standard_041613.pdf

Program Characteristics: RNG voluntary programs are generally on a cost recovery basis, where the cost is recovered by the participants and not through the entire customer base. This was generally the case for programs where the mix of RNG and offsets were being offered. Deferred accounting for programs was identified in two programs to manage high initial administrative costs. For example, the Blackhills program proposed in Colorado is requesting a deferred accounting mechanism to give the company an opportunity to recover the deferred costs in the future as program participation increases. In this case, Blackhills indicates in the early years of the pilot the anticipated expenses associated with upfront marketing costs in acquiring new participants are greater than the anticipated revenues due to low initial participation. The imbalance is expected to result in expenses exceeding revenue. In subsequent years, increased enrollees could generate revenue more than program expenses, creating a regulatory liability. If the program becomes over-collected, the company will use the excess revenues to benefit program participants by either acquiring more RNG and/or higher premium carbon offsets which would increase the CO_2 emissions offset with each block enrolled. The FortisBC program currently allows for distribution of costs across the entire utility customer base, thus the program does not need to be on a cost recovery basis, allowing for greater purchase ability by the utility. FortisBC has used this cost recovery certainty to secure long-term contracts with many RNG producers.[71] Several of the proposed programs were investigating the potential to sell the environmental attributes associated with gas that was procured but not required by the voluntary program users each year. This would allow for some cost recovery and help to smooth out program costs.

Marketing/Administration Expenses: Comparison of marketing expenses could not be done across all programs as many of the program costs were redacted from public documents or were not provided. Of those that were provided, there was a considerable range in costs associated with the programs and the type of costs included. SoCalGas estimated the marketing costs for the first 5 years of their program will be approximately $330,000 USD, starting at $90,000 USD in year one and $60,000 USD per year thereafter.[72] No estimate of quantities of RNG associated with the program were given to determine the percentage of marketing dollars spent per unit of RNG procured. Blackhills Gas in Colorado estimated their marketing costs will range from $87,500 USD per year to $119,750 USD per year for approximately 2900 customers out of 195,000 total eligible customers.[73] In the first year of the program they anticipate displacing 174,363 therms of natural gas; however, the cost RNG and offsets were not given to determine the percentage of marketing dollars spent per RNG procured. Dominion Energy estimated the total expenses to admin ratio for the first two years of their RNG program (2020-2021) went from 19% to 4% as new participants were added to the program.[74] DTE's 2021 Annual Report indicates their total program costs were approximately $1,221,685 USD of which 4,211 tCO_2e was procured as offsets at a cost of $33,685 USD, and 4,044 mcf of RNG was procured at a cost of $127,652 USD. Direct marketing costs were approximately $775,000 USD. Of the total cost of the program only 10% of the budget went to the procurement of RNG.[75] These final two examples suggest that marketing expenses associated with

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[71] Table 6-1, https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf

[72] Chapter 7: Grant Wooden Program Design, https://www.socalgas.com/regulatory/A19-02-015

[73] Hearing Exhibit 101 -Attachment MJC-1, https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_790732

[74] Dominion Energy, 2022. 2021 Annual GreenTherm Program Summary Report. Docket No. 19-057-T04. June 30, 2022.

[75] DTE, 2022. DTE Gas Natural Gas Balance (NGB) U-20839, Program Update and 2021 Annual Report, March 18, 2022. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000002U2pfAAC

voluntary programs may consume a large portion of the budget that could be used for procuring additional RNG into the system.

Procurement Strategy: Details of procurement strategies including the timing of purchases, the long- and short-term commitments, and the prices paid for each green energy product were generally not provided in the public applications or hearings documents as this is often proprietary information that producers and marketers do not want disclosed in public documents.

Some programs, such as Vermont Gas, noted that if they were not able to procure enough RNG supply at a given time, they would purchase equivalent carbon offsets to meet demand. This, however, would only last for 30 days, after which time the company would notify customers of the shortage and options going forward.[76] Vermont Gas also noted that for any excess RNG not sold under the program, they may market the carbon offsets or any other available environmental attribute relating to RNG and revenues generated would be used to offset the cost of the RNG program. This flexibility would tend to allow Vermont Gas to increase its purchased volume. Like the lever of longer-term contracting, purchasers of higher volumes of RNG may realize more favorable discounted pricing terms from RNG sellers.

[76] https://epuc.vermont.gov/?q=node/104/16215/FV-Legacy-EXHDOX-PTL

4.0 Structural Overview of the North American RNG Market

North America has an active renewable natural gas ecosystem. RNG supply is produced at several types of facilities that capture methane resulting from the decomposition of biological wastes. Demand for RNG is growing in several key sectors to drive development of supply. With adequate processing and access to injection points and required approvals, RNG can be injected into the vast North American natural gas pipeline grid.

The interconnected pipeline network serving North America transports natural gas and RNG on the concept of “delivery by displacement” and “book and claim” transaction. North American gas market producers can inject and book RNG molecules at one point of the North American network that can be delivered and claimed by consumers elsewhere. This ability to move RNG across the continent or multiple jurisdictional borders is a great advantage in drawing supplier project capital and assuring consumers can access RNG decarbonization benefits.

- **Reliance on Bilateral Deals:** Most producers and project developers seek the highest value for their product with the lowest risk by seeking to serve the highest value market on a long-term basis with the greatest volume. To do so, supply projects must line up consumption and offtake agreements. These are often done independently and over the counter by the project operator or in concert with third-party environmental attribute marketers and brokers. Exchange trading of RNG as a renewable commodity has recently become a reality on the M-RETs exchange via Renewable Thermal Certificates (RTC). These RTCs are one dekatherm units of RNG (1.055056 GJ) with fully specified properties including product parameters, carbon intensity scores, and more. In rulemaking documents for California's Senate Bill 1440, the California Public Utility Commission (CPUC) ordered utility buyers of RNG to require their contracted producers to track RNG injections with the M-RETs platform as a default.[77] After weighing submitted comments by RNG producers that clearly expressed a preference for long-term duration contracts of between 10 and 20 years, the same CPUC document included an order stating that RNG procurement contracts can be no longer than 15 years. In a recent investor call, one publicly traded RNG producer noted their commercial business plan seeks to lower RNG transportation market and pricing risks by selling 60 to 70% of production at discounted stacked prices under long term contracts to investment grade stable parties. They also noted they hold the remaining portion at risk for spot market transportation transactions which may offer upside price potential.[78]

- **Roadway Transportation Sector as RNG Primary Driver:** Most current North American RNG demand originates within the transportation market amid compliance requirements for transportation decarbonization. The highest value for RNG is therefore often found in the transportation markets where RNG is prized for deep decarbonization properties as recognized by regulatory compliance programs for both direct and indirect emissions. These programs exist in multiple jurisdictions and at both national and regional levels. (See below for more on California LCFS, B.C. LCFG, U.S. RFS, and Canadian CFR, etc.). Given the current level of supply and demand, the California transportation marketplace is often the target of North American RNG project developers across the continent. The

[77] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M454/K335/454335009.PDF
[78] https://ricespac.com/wp-content/uploads/2021/04/Rice-Acquisition-Corp.-Archaea-Energy-Investor-Presentation-Transcript-04.07.2021.pdf

California market can be reached easily via the use of existing book and claim accounting and continental pipeline infrastructure.

- **Life Cycle Carbon Intensity Drives Compliance Value:** Unlike voluntary green gas programs, existing regulatory programs set the carbon value for RNG based on its lifecycle carbon intensity as a low carbon volume fuel which can be flexibly used in existing natural gas engines. RNG produced from specific feedstocks and utilizing acceptable production protocols with quantifiable life cycle carbon performance from producer to consumer can be deemed to qualify for credits. For example, the U.S. RPS sets volumetric targets for the usage of various renewable fuels, and credits are granted for the fuels based on volume supplied and consumed. Fuels can also be valued on a sliding scale with life-cycle CI scores representing the amount of carbon embodied and released in a unit of energy contained within the fuel. RNG fuels with lower carbon intensity afford higher decarbonization compared to a conventional fossil fuel baseline. The lower the CI, the higher the value, as shown in Table 4.1.

Table 4.1: California LCFS Transportation Credit Value vs Federal RIN Value Elsewhere

	Swine Farm RNG	Dairy Farm RNG	Food Waste RNG	Landfill RNG
Federal RNG Value in RIN / RFS Program	**$36.47/MMBtu** (Includes D3 on 5/18/22)	**$36.47/MMBtu** (Includes D3 on 5/18/22)	**$36.47/MMBtu** (Includes D3 on 5/18/22)	**$36.47/MMBtu** (Includes D3 on 5/18/22)
State RNG Value in California LCFS Program,	**$74.82/MMBtu** (Includes RFS+ LCFS on 5/18/22 with -400 CI)	**$58.81/MMBtu** (Includes RFS+ LCFS on 5/18/22 with -200 CI)	**$42.81/MMBtu** (Includes RFS+ LCFS on 5/18/22 with 0.0 CI)	**$40.24/MMBtu** (Includes RFS+ LCFS on 5/18/22 with +32 CI)

Source: Anew Advisory representations of Argus 05/18/2022 price per Jaffe et al method

- **Calculations Methods for Stacked RNG Value:** Natural gas, renewable or otherwise, always has a thermal value. But RNG can have additional value if it qualifies for various credits and incentives in overlapping compliance markets. For instance, a volume of RNG sold in California can reap the value for thermal energy, the federal RFS credit, and the state LCFS value. We illustrate with this example:
  - The value of natural gas as an energy source provides the base starting value for stacked RNG valuations. For example, if the fossil fuel energy value of natural gas in the California market is $USD 9.00/MMBtu, then the RNG sold in that market should also get that same value since it is of pipeline quality and chemically identical.
  - To that fossil price, the environmental value of the RNG under the US Federal RFS and can be calculated independently and added in. The RFS value for RNG is based on RIN market values. RIN values are quoted in $USD/gallon but can be converted into $USD/MMBtu. Cellulosic RNG is valued with D3 RINs. Other RNG types made from sugars, fats and other non-cellulosic biologic feedstocks are typically valued with lower-cost D5 RINs. To convert the $/gallon price of a RIN to $/MMBtu for RNG sales, a multiplier of 11.727 is used.[79] That is, if a D3 RIN costs $USD 1.00/gallon in the market, then spot buyers of cellulosic RNG that qualifies under the RFS program would generate credit worth $US 11.72/MMBtu. Non-cellulosic RNG is produced from non-cellulosic waste sugar beet

[79] https://www.rngcoalition.com/calculators-conversions

feedstocks, for example. If we see that D5 RINs costs $USD 0.75/gallon, then the RSF value of the D5-compliant RNG would be $USD 8.80/MMBtu.

- To the fossil and Federal RFS price, an additional credit for qualifying gas used in California can be realized under the state LCFS program. The LCFS program awards credits to transportation operators utilizing fuel with delivered carbon intensity below a reference value relevant to the fuel. For gaseous fuel, the California LCFS program uses a reference base CI value of 79.21 gCO_2e/MJ for pipeline-delivered fossil gas that is compressed and used in CNG vehicles[80`]. Using that, we can determine the LCFS value of a hypothetical RNG from a project whose California market delivered CI, as certified by CARB, is 59.21 gCO_2e/MJ. A vehicle driving in California on this fuel would be counted as abating 20 gCO_2e/MJ of CO_2 equivalent on an energy unit basis. Yet LCFS credits are priced in $USD/tonne of CO_2 equivalent abated. The application of appropriate unit translation factors (1000000 grams to 1 tonne and 1055 MJ to 1 MMBtu) onto the pathway's RNG abatement allows the determination of the RNG under the LCFS program in $/MMBtu[81]. So, for an $80/tonne LCFS credit value, the use of this low carbon RNG would be rewarded with $USD 1.69/MMBtu in LCFS credit value.
- The stacked fossil thermal energy and both federal and state environmental values would sum up in this example to a spot price of $USD 22.40/MMBtu. If the RNG of the same CI and LCCFS value could only qualify for D5 RINs, then the stacked value would be a lesser spot price of $USD 19.49/MMBtu.

- **RNG is More Than a Motor Fuel:** Where simplicity is favored, or where gas processing and/or pipeline injection is unavailable or infeasible, RNG is also used outside of the transportation sector Similar to natural gas, RNG is used to generate power or heat for local purposes. The B.C. LCFS awards value for uses of RNG to displace natural gas used in building heat or power generation uses. Applications range across agriculture, university or district heat, renewable electric power generation, and other valuable purposes. RNG demand can be collocated with an RNG production project site or may be interconnected by midstream logistics. The interplay between the RNG project's development timeline, partner contributions, and contractual relationships are illustrated in the arrangements disclosed between Vermont Gas and Middlebury College, and one RNG project operator.[82]

- **Transportation Markets Change:** Each year, transportation markets tend to see a wave of newer compliance requirements that mandate more stringent decarbonization ambitions. Technological change adds its own dynamism to transportation fuel markets. For example, renewable diesel producers are investing and building out substantial capacity to fuel transportation with lower carbon impact. Manufacturers of electric vehicles, batteries, and charging point technologies are commercializing more choices and capacity. Compliance obligations face periodic resets and grants of waivers. Each drive further changes into the renewable fuels marketplace.

[80] See table 7-1, https://ww2.arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf
[81] See Table 12 in Jaffe et al in The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, June 2016, Institute of Transportation Studies Univerisity of California - Davis, Report UCD-ITS-RR-16-20. https://steps.ucdavis.edu/wp-content/uploads/2017/05/2016-UCD-ITS-RR-16-20.pdf
[82] Middlebury College and Project Partners Celebrate Groundbreaking for Facility That Turns Manure and Food Waste into Renewable Energy | Middlebury News and Announcements

- **Fuel Markets Offer Innate Volatility**: On top of those compliance dynamics, underlying variability in fuel demand is seen to play out in the transportation markets from season to season and year to year. The appetite for transportation fuel is influenced by the economic cycle, consumer spending capacity and appetite for travel overall. For producers selling RNG into transportation compliance markets, and for transportation fuels providers vending into these markets, RNG price volatility and cyclicality are a well-known fact.

- **Pre-Compliance Mandates**: Beyond roadway transportation, other broader transportation market decarbonization rules are pending. Decarbonization efforts are underway in major jurisdictions within the aviation and the marine industries. Participants on both transportation value chains are devising techniques and technologies to utilize RNG as a drop in fuel or as a feedstock for other advanced low carbon transport fuels.

- **Carbon Intensity Varies by Project:** In supplying RNG to a consuming region, each step in the RNG supply chain influences carbon content of the RNG. Energy is used and CO_2e footprints can swell from producer to processor and through long-haul logistics and ultimately in the last-mile distribution and consumption. Each link in the value chain introduces and embodies varying levels of carbon emissions within the product. Due to differing production, processing, and logistics pathways, not all RNG has the same carbon intensity at the meter.

- **RNG CI Starts with Supply**: Unless produced in a gasifier or other advanced methods, most commercially available RNG results from the managed decomposition of waste biologic materials in landfills, wastewater treatment plants, and in masses of agricultural waste. RNG that has been produced from waste is "biogenic", as it came from, and is going to return to, the natural biological cycle involving growth and decay. Biologic waste materials at one time were alive and the carbon and CO_2 within were part of the normal biogenic natural climate. That is one of the fundamental premises as to why the combustion of RNG is considered renewable and carbon-zero fuel. As biogenic methane burns, its direct combustion releases no new anthropogenic CO_2 emissions which result from the combustion of produced geologic gas. For greenhouse gas programs that seek reductions in carbon emissions from a baseline, the lifecycle CI of RNG would incorporate the direct carbon neutrality of biogenic fuel combustion. But CI-based programs also would include production chain effects including feedstock handling, processing, pipeline logistics, leakage and even avoided emissions. Conversely, many compliance programs value and recognize only the direct combustion decarbonization properties of RNG. This includes the current Canadian federal GGPPA that collects zero tax on a 1:1 basis for each volume of fossil fuel switched out with biomethane regardless of its lifecycle carbon intensity. Under the GGPPA, for instance, RNG CI scores do not add or detract from the 1:1 tax abatement afforded by using RNG that meets the program definition of biomethane.

- **RNG Utilizes North America's Pipeline Infrastructure:** Book-and-claim transfers of the environmental attributes and the physical volumes of RNG have become the norm. Using North America's vast pipeline infrastructure, RNG may be produced and processed in one part of the continent, injected into a pipeline locally, and claimed by any consumer with a deliver point meter and the willingness to pay for both the physical commodity and the environmental attribute.

FIGURE 4.1: RNG Market Reached by North American Pipeline Network

Source: US Energy Information Administration (EIA)

- **RNG is Biogenic and Carbon Neutral when Combusted**: During the growth of plant material, carbon becomes sequestered within their leaves, cellulose, and woody structures. Later, the unused plant matter decays naturally or is harvested as trees and crops to become wood products, paper, food, and more. As biogenic material decays after its natural or service life, methane is produced where it is allowed to decompose anaerobically. Forest fires, field burns or other events that combust plant material do emit carbon but only that which was biogenically sequestered originally. Similarly, the combustion of biogenic methane does emit CO_2, but it is considered biogenic CO_2 rather than anthropogenic CO_2.

- **RNG Can Be Carbon Negative:** The investment in and operation of RNG collection facilities at landfills, wastewater treatment plants and farms prevent the escape of biogenic methane. Although zero anthropogenic CO_2 is emitted if successfully combusted, any uncombusted methane released into the atmosphere causes climate warming. Methane is seen to be a potent greenhouse gas that warms the climate several times more deleteriously than even pure carbon dioxide. If producers capture biogenic methane and this RNG displaces non-biogenic fuels, then combusting waste derived biogenic RNG can be seen not only as a zero carbon fuel but also a carbon negative gas substitute.

- **Modelling CI for RNG:** Jurisdictional regulations determine which modelling methodologies are acceptable and whether avoided emissions are recognized or not. Each jurisdiction chooses the calculation tools and approaches which set the foundation for the RNG CI. The major software tools used by producers and their engineers or marketing partners for CI modelling include Canada's

GHGenius model, the Canadian FUEL-LCA tool for the Canadian Clean Fuel Regulation the Argonne National Labs GREET model, or the California LCFS lifecycle pathways incorporating the CA-GREET model. All of these models include negative or avoided emission in calculated RNG CI values. These then form the basis for resulting RNG credit valuation that producers can expect. The lower the CI, the higher the value in CI-dependent regulatory compliance and incentive programs. Higher value for lower CI is also seen in voluntary buyers that seek to abate GHG emissions and meet voluntary GHG reduction targets. Even in jurisdictions that currently value only volumetric performance of RNG in zeroing out direct emissions, the use of RNG with lower CI should have more longevity as decarbonization ambitions advance and low carbon fuel blend rates escalate.

- **Different RNG LCA Tools**: On top of non-uniform jurisdictional views on avoided emissions, RNG values and CIs are often differentiated among types and jurisdiction because of life cycle analysis tools. Each methodology, pathway to market, and calculation tool will show different CI impacts for the waste handling, production process, processing, and logistics of converting waste into marketed fuel. A local project may incur a higher impact from carbon-intensive power used during production, for example, but may have access to shorter pipeline pathways to market that can limit carbon impact of logistics.

- **RNG Flexibility:** Entities across the economy are seeking decarbonization under voluntary and compliance initiatives. RNG can be marketed to enable the decarbonization of gas consumption at all levels including within residential, commercial, and industrial accounts. Heat, power, and steam can be produced with RNG equally as well as with geologic natural gas. But because RNG is so flexible, any RNG consumer must meet or beat the prices set for the market. And the current market setting prices are in the regulated transportation compliance markets that value RNG for its deep decarbonization properties. Some jurisdictions also award credits for renewable power produced by combusting RNG. Yet these power credits are typically valued lower than those in transportation compliance markets.

RNG offers consumers across the economy a highly effective decarbonization fuel and feedstock that is readily useable in essentially all the same applications, with the same infrastructure and uses currently served by geologic natural gas. RNG use can lower corporate scope emission tabulations for reporting purposes and reduce the footprints of delivered goods to trading partners. Potential RNG demand reaches across the economy and into every area served by geologic natural gas.

Currently, the growing RNG producer network can deliver just a fraction of overall natural gas volumes being consumed in North America. All RNG that is destined for pipeline use must be processed to pipeline quality specifications. The complexity of processing and requisite capital costs is incurred no matter the project size (permits, electrical substations, land procurement, etc.) While larger RNG projects can spread fixed investment costs across more RNG volumes, smaller projects can not. This has limited development of many smaller and marginal-volume RNG producing opportunities. But as policies are put in place to recognize the full array of RNG benefits – namely, avoided emissions via CI programs that reward the avoidance, capture and use of biogenic methane otherwise off gassed, then more RNG supplies can be economically produced, valued, and supplied even at smaller scale. This will expand the availability of the most potent forms of carbon-negative RNG that can then decarbonize more of the North American economy.

Book and claim deliveries of RNG through the interconnected North American pipeline network minimizes the carbon footprint of transporting and distributing RNG. Consumption of RNG can be not only carbon neutral but carbon negative as well. In addition to transportation market uses, RNG can be used in building heat and in industrial facilities such as chemicals, steel and refining that utilize methane molecules for both feedstock and thermal fuel.

5.0 Factors Affecting RNG Supply, Demand and Pricing

The RNG marketplace of key regions within North America is driven mainly by compliance programs that reward low carbon intensity fuel used for transportation markets. Project developers weigh project costs against profit potentials within both the traditional compliance market and emerging voluntary decarbonization markets. Project economics are in turn underpinned by location, feedstock types, midstream infrastructure and more.

The key drivers of current supply, demand and pricing are considered and analyzed below. For consumers of RNG in either compliance or voluntary markets, the imminent focus will be how to lock in long-term RNG supply earlier rather than later. Competition for supply could drive competing consuming entities to seek long-term supply agreements from producers. Speed is of the essence in building out the best and most impactful RNG projects. Gas utilities are seeking to decarbonize their supply chains, markets, and operations before other demand for RNG accesses the most economic supply.

5.1 Factors Affecting North American RNG Supply

Amid the energy transition, we anticipate RNG supply will grow as favorable project economics are underpinned by policy-driven supply and demand incentives. Investors seeking returns on their investment will certainly review RNG production and infrastructure projects as more voluntary and compliance buyers seek effective low-CI gaseous fuels. While supply potential forecasts by multiple entities have shown significant opportunity to expand RNG supplies, the output of most North American projects will seek the highest value markets. The markets with rules and methodologies that properly values RNG will define the highest priced markets. It will be those prices which must be met or exceeded by buyers in Ontario. Careful structure of Ontario policy and programs can draw supply of decarbonizing RNG, especially the most potent carbon negative kinds, which could enable Enbridge Gas RNG buyers to realize significant decarbonization at relatively manageable costs.

Sustainable RNG projects that earn risk-adjusted returns need market prices above production costs. With a sightline on favorable returns, sustained project investment in RNG can be expected. However, the energy transition is presenting a myriad of technological approaches and risk and return profiles that will compete for capital investment. The inventory of potential project sites must be diverse and large enough to capture attention amid the noise and disruption of the energy transition.

While there appear to be sufficient project opportunities and economics to scale RNG supply considerably, the productive output at each project is likely to become incrementally smaller. Many projects will need to be developed and operated to inject gas into the pipeline grid to sustain meaningful outputs through seasonal production and maintenance periods that are inherent with RNG infrastructure. The most productive plants with the lowest capital intensity will likely be developed well before the more numerous but smaller projects. From an RNG procurement standpoint, the utilities, or other buyers that act with urgency will likely find the lowest prices for RNG. That should be especially true for larger stable customers that can procure large volumes over the long term. Both term and volume will tend to attract RNG producers as they seek to lower pricing risks in the volatile transportation markets.

- **Project Development Appetite and Financing:** To grow RNG supply, more project investment is needed in North America. The appetite for investing capital in RNG projects will be furthered by sustainable margins that meet risk-adjusted returns. These in turn are underpinned by market prices that exceed production costs. With successful and sustained project investment, RNG can be expected to see supply expansion in North America. The inventory of potential project sites across the continent must also be diverse and large enough to capture attention among all the other opportunities for capital investment and returns amid the unfolding energy transition. While there appear to be sufficient project opportunities and economics to scale supply considerably, the productive output of each project is incrementally small. Many projects will need to be developed and operated. The least capital-intensive projects with high volume output will likely be developed before smaller or marginal projects.

- **Production Costs and Infrastructure Availability:** The cost of RNG production per unit of energy produced differs based on many factors. These include project size, upgrading requirements, maintenance, seasonality, distance to natural gas infrastructure, technology type, proximity of feedstock, quality of feedstock, and more. Capital costs estimated by capital market analysts for different types of RNG projects can range up to $228 USD per Dth/d of output from swine or dairy-sourced RNG projects, up to $190 USD per Dth/d for digesters at wastewater treatment plants (WWTPs), and between $35 and $40 USD per Dth/d for landfill gas-facilities. Utilizing $1.00 USD to $1.278 CAD and 1 MMBtu to 1.055056 GJ, we can convert the above four referenced costs to 276, 230, 42 and 48, respectively, all expressed in $CAD per GJ/d.

Table 5.1.1: Capital and Operating Cost Ranges (USD$)

	Output, Dth/d	Capital Expenditure (Stifel), M$	Capital Expenditure (RBS) M$	Operating Expenditure (Stifel) M$/yr
Dairy Farm AD	84	$7 or 228 $/Dth	$10 or 125 $/Dth	$0.2 or 6.50 $/Dth
Swine Farm AD	878	$50 or 156 $/Dth	Not available	$2.1 or 6.55 $/Dth
Wastewater AD	88	$6.1 or 189 $/Dth	$15 or 50 $/Dth	$0.1 or 3.11 $/Dth
Landfill	2,071	$27 or 35 $/Dth	$30 or 40 $/Dth	$4.0 or 5.29 $/Dth

Source: Anew Advisory presentation of estimates by Stifel Equity and RBC 2021 research

Costs could escalate if a project must cover an outsized share of interconnection cost or meet specialty processing and pipeline specifications. The resultant CI benefits of a given project's RNG would also be diluted if nearby pipeline injection points were not readily available. Project developers may avoid projects requiring significant investment in interconnecting pipelines or, alternately, in virtual pipeline solutions. Virtual pipeline solutions require investment and operating costs for compressors, liquefaction, loading racks and/or trucking logistics.

- **RNG Project Counts from Key Industry Associations:** The Canadian Biogas Association and its U.S. counterpart, the Renewable Natural Gas Coalition, both show strong historical and future RNG project growth. A considerable inventory of landfills has the potential to produce biogas. While many uses for landfill gas include local heat and power generation, the most likely near-term use for biogas that can be converted into RNG by processing is currently in the transportation market, which draws RNG to beneficial use and out of the flare systems and local energy pool at landfills. Furthermore, North America is a rich agricultural region that as a result has great biogenic agricultural waste potential. While population centers host both WWTP and separated food refuse generation opportunities, costs of developing projects based on these feedstocks will likely be limited. The SMART targets of Table 5.1.2. are from the RNG Coalition's action plan for waste sites in the US and Canada.[83]

- **Sustainable Methane Abatement & Recycling Timeline, The** SMART initiative that seeks to capture and control methane produced from the 43,000+ aggregated organic waste sites in the U.S. and Canadian portion of North America.

Table 5.1.2: RNG Project Counts

	Current Tally	SMART Target 2025	SMART Target 2030	SMART Target 2040
Operating	251	There is strong visibility on the 2025 SMART target of 500 operating projects given current tallies.	Reaching 1000 projects in operation would represent a CAGR of 14% in the 2nd half of this decade.	Reaching 5000 projects in operation by 2040 would represent a CAGR through the 2030's.
Under Construction	119			
Planned	138			
Total Sum	508			

Source: RNG Coalition data online and within Wastedive.com interview of Johannes Escudero

- **RNG Potential Assessments by Jurisdiction**: In their widely cited 2019 study[84] for the American Gas Foundation (AGF), consultants at ICF considered nine feedstock categories and 3 RNG producing technologies to create Low/High/Technically possible supply assessments of RNG potential within U.S. national and state jurisdictions for 2040. These tri-level assessments of potential future RNG projects are like the Proved/Possible/Probable resource assessments done for decades within the geologic natural gas industry. While one potential project may reflect production from waste resources and another starts with geologic resources, both approaches assess potential gas producibility given technology, operational and economic constraints. Of the nine RNG feedstock categories studied for AGF, the most prevalent in the marketplace today is RNG from landfills and manure projects. The three technologies assessed by the AGF study include anaerobic digestion, thermal gasification, and power to gas projects.

  Looking at those two classes of RNG in one jurisdiction (Michigan), we see that the Michigan forecasts for RNG from landfills published by ICF in their 2019 AGF study showed low, high, and technical resource potential estimates in 2040 of 25.2, 41.0, and 62.0 trillion Btu/y respectively (26.6, 43.3 and 65.41 PJ/y). By 2022, a study produced by ICF for the state of Michigan [85] showed potential estimates

[83] RNG Coalition SMART Initiative Plan to Utilize Methane Capture — The Coalition For Renewable Natural Gas
[84] https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf
[85]R https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/RenewableNaturalGas/MI-RNG-Study-Draft-Report---6-2022.pdf?rev=abfd113cf24c434d874a16bc187bae84&hash=EC2FF77C337D13929B262376B8618208

in 2040 for "Achievable", "Feasible", and "Inventory" RNG in 2050 at 31.5, 53.5 and 67.8 tBtu/yr (33.2, 56.4, and 71.5 PJ/y, respectively). The assessment showed a gain of as much as 30% in Michigan over the decade even though the earlier study in 2019 showed overall U.S. RNG assessments for landfill gas (LFG) RNG flat after 2035. Regarding RNG from manure projects, Michigan's 2050 technical resource potential as assessed in the 2022 study nearly tripled over the 2040 potential estimate 3 years earlier (rising to 39 tBtu or 41.1 PJ/y from 13.8 tBtu or 14.6 PJ/y).

We also note that the assessments by ICF did not consider avoided emissions for all RNG types. ICF set their assessments for RNG by keeping carbon intensity at zero. This simplified approach to pricing RNG is different than the rules of the California LCFS program and does not consider the profit motives of developers seeking to sell into the LCFS program. Instead, they simply recognized that biogenic RNG has zero carbon intensity.

Conversely, other similarly influential RNG resource assessment studies have been authored for Canadian jurisdictions (Torchlight Bioresources, 2020).

The Torchlight study determined feedstock conversion potentials for projects including anaerobic digestors and gasification technologies. But it characterizes the gasification technologies as "demonstration-scale" and "pre-commercial." Furthermore, "wood-to-gas" gasification technologies "should not be considered a significant contributor to RNG volume by 2030 and perhaps not by 2040." The Torchlight forecasts also do not include any commercialization of the power-to-gas technologies that may add RNG supply into the market.

Nonetheless, we offer herein a survey of supply potential from these non-commercial sources by reviewing studies pertaining to the broader North American and U.S. marketplaces. The RNG Coalition's North American data shows that from a 2017 base (242,000,000 ethanol gallon equivalent), the RNG used for North American transportation markets has grown at a compound growth rate of 24%[86]. If RNG supplies grow at that rate until 2030 from a 2021 base of 66.7 tBtu/y (70.4 PJ/yr)[87], then supply that year would average 454 tBtu/yr (479 Pj/y).

But we join with authors of the AGF and Torchlight studies in expecting forward RNG market growth overall to exceed the forward RNG growth in the transportation segment. From a 65 PJ/yr base estimated for the U.S. alone[88], we calculate that a compound annual growth rate of 29% would be required to meet the AGF report's forecast for U.S. Low Potential supply for 2030 at 689 PJ/yr. We note that this tally includes the AGF forecast for zero expected production of RNG from thermal gasification in 2030. The position to exclude thermal gasification for RNG supply prior to 2030 matches the position taken by the Torchlight authors. While AGF and Torchlight were of the opinion that thermal gasification produced sources of RNG may not be realized by 2030, it should be noted that two wood-based thermal gasification projects in Canada have been announced by REN Energy

[86]ttps://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/627027440ad1fc1e4922b215/1651517252292/NGV+RNG+Decarbonize+2022+5+02+22.pdf).

[87] We determined this baseline for 2021 by growing the 2020 operating RNG capacity of 59 million Dth/y as reported by NGV America in a study by Energy Vision and noted at https://ngvamerica.org/2020/12/22/new-assessment-shows-rapid-expansion-of-u-s-renewable-natural-gas-industry/ with the 2020 and 2021 transportation share of the market as reported by The RNG Coalition.

[88] About 6 Pj/y less than the N. Am total, as estimated for canada at https://biogasassociation.ca/resources/canadian_2020_biogas_market_report

International Corp in Ontario and British Columbia[89],[90]. The AGF study does show Low Case forecasts for power-to-gas RNG which we read as adding about 240 PJ/yr to North American supply if that forecast is realized. For comparison, the AFG High Potential case shows that a sustained growth rate of 40% through 2030 would be required from the current base to reach the study's 1,443 PJ/yr forecast for U.S. RNG output in 2030. The 2040 forecast production of advanced thermal gasification technology output in the US represents 8% of that High case forecast. The AGF High case also shows forecasts for power to gas technology in the U.S., and from those we see that they could add 30% more RNG supply on top of the conventional and advanced thermal gasification estimates for the year.

In addition to highlighting the quantity of RNG potentially available in Canada, the Torchlight study highlighted the importance of the quality of the RNG as well in that the study valued avoided emissions. From the study, we see that RNG supply from anaerobic digestion of non-crop biogenic feedstocks will be insufficient if avoided emissions are not recognized, captured, valued and utilized. The study quantified approximately 70 PJ/yr of "Feasible" waste-based non-crop conventional RNG resources in Canada. The study notes that "from a national energy policy perspective, 70 PJ/yr is only 0.6% of Canada's current energy consumption. This limited volume means RNG will not be able to displace a large quantity of fossil fuels for GHG reductions." Further, the authors state that while "the quantity of fossil fuels that can be displaced with conventional RNG is quite limited," the analysis "determined that RNG can make an important contribution to decarbonization in Canada … Avoidance of methane emissions is likely to be the largest contributor of RNG to Canada's climate strategy."

The study estimated that conventional feedstocks could produce RNG with an average positive CI which, while 65% below geologic gas, the study concluded that "high on the list of priorities should be AD projects that utilize feedstocks with negative value and/or have a negative carbon intensity. These feedstocks include manure, urban organics, and biosolids. … the avoided methane emissions …should be recognized in the value of the RNG." We note that BCUC-approved FortisBC's RNG procurement programs have, as of 2021, led to a weighted average CI of –22 gCO_2e/MJ.[91] This was all the while complying with the BCUC $30/GJ RNG acquisition price cap. The cap was raised to $31/GJ for 2022 forward to further support RNG and reflect inflation.[92]

In conclusion, we believe RNG potential forecasts for North America do indicate strong supply potential for RNG in North America. The supplies of conventionally produced RNG from anaerobic digestion projects will likely lead supply through at least 2030 which is when the forecasters surveyed in this report expect material contributions by thermal gasification or power-to-gas technologies. Yet it is the recognition of both the carbon zero and unique carbon negative qualities of RNG, and not its rising quantities alone, that we expect will drive rapid and positive climate impact. The technology and feedstocks that will produce significant RNG volumes in the future are likely different than what some top-down models indicate. Therefore, we believe that a bottom-up approach that focuses on project counts and includes avoided emissions is more indicative of RNG supply growth.

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[89] A renewable natural gas plant is proposed for the District of Thunder Bay - SNNewsWatch.com

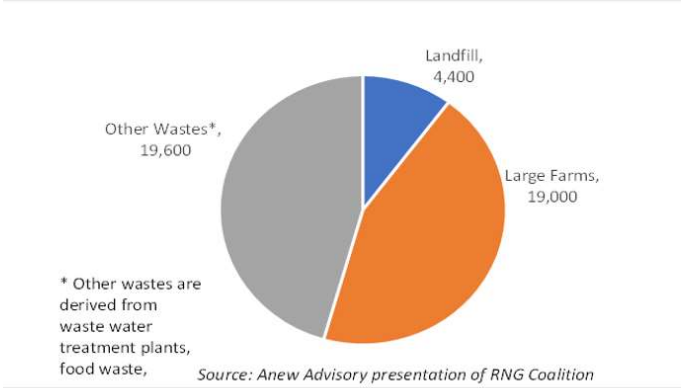
[90] A first for North America: FortisBC, REN Energy to produce RNG from wood waste - Canadian Biomass Magazine

[91] Page 47 of 266, FEI Stage 2 Revised RG Program BCUC IR1 Response (fortisbc.com)

[92] Figure 2-1 within DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf (bcuc.com)

- **RNG Coalition Potential Project Inventory**: The RNG Coalition counts nearly 47,000 waste facilities in North America that could be developed for RNG production. While North America hosts more landfills than that, roughly 4,400 sites are seen by the RNG Coalition as potential RNG production sites. At the early part of last decade, according to the RNG Coalition, nearly 100 % of all RNG produced was at landfill projects. Today, 70% of projects nearing startup are landfill gas sites. Of those in the early phases of construction, 45% are at landfill sites. These trends show that developers are diversifying capital investment into the Large Farm and Other Waste categories. These categories of RNG producing facilities are capable of capturing value from lower carbon intensities and avoided emissions.

Figure 5.1.1: North American Potential RNG Project Site Inventory



If 4,400 potential landfill projects were developed to yield 2,000 Dth/d each, they could produce 8.8 million Dth/d (9.28 PJ/d). For CI-sensitive programs like the North American LCFS programs, RNG that is injected and delivered with an average 45 gCO_2e/MJ CI (versus geologic gas at an estimated 70 gCO_2e/MJ) could fully decarbonize 3 million Dth/d (3.16 PJ/d) of LDC gas. We use 70 gCO_2e/MJ as a general unmitigated reference value since it is the average of the three reference values for unmitigated carbon intensity used within the BCUC LCFS[93], California LCFS[94], and Canada RFS[95] compliance transportation programs (63.64, 79.21, and 67.0, respectively, all values in gCO_2e/MJ).

If all farm digestors were developed to yield 350 Dth/d with a grid-injected CI of -350 gCO_2e/MJ, this 6.65 MM Dth/d (7 PJ/d) of farm RNG could decarbonize 40 million Dth/d (42.2 PJ/d) of grid gas use. If the "Other" RNG projects were developed to yield an average 100 Dth/d with an injected CI of 0 gCO_2e/MJ, then Other RNG could decarbonize the direct emissions of that same volume (1.96 Dth/d or 2.07 PJ/d) of consumed grid gas.

The North American project inventory could produce a combined potential 17.4 million Dth/d (18.4 PJ/d) which if under a CI program like the CA LCFS, could fully decarbonize the equivalent of 45.7 million Dth/d (48.2 PJ/d) of geologic gas in the grid. If that RNG was used in volumetric programs that count any RNG as simply carbon neutral (CI=0), then these projects could only decarbonize the direct emissions from the volume of geologic gas that they displace on a 1-to-1 basis. Current EIA data for the US and Canada peg natural gas consumption at 84 million Dth/d and 11.4 million Dth/d (88.6 and

[93] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/210526-fei-sec-71-shell-bpa-bcuc-ir1-response.pdf?sfvrsn=f9e6f53c_2

[94] See table 7-1, https://ww2.arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf

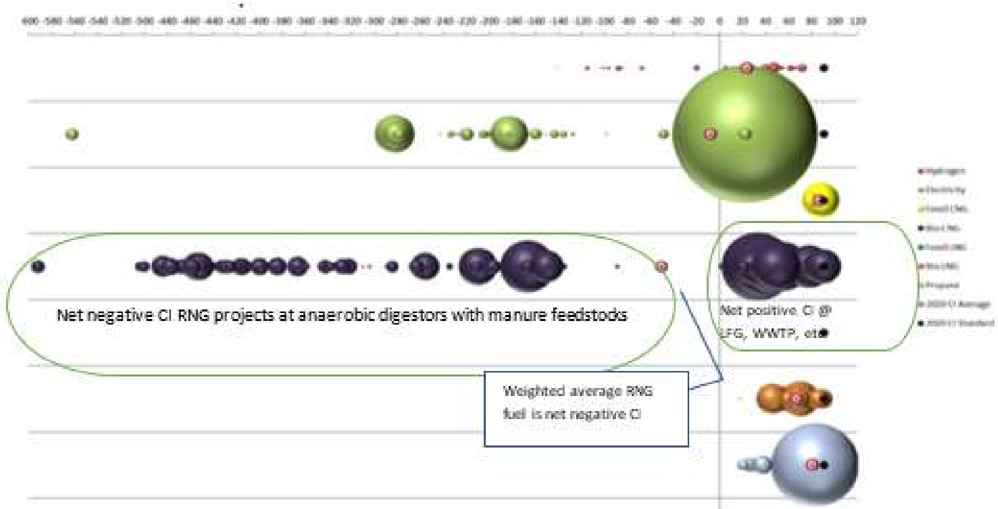
[95] https://www.gazette.gc.ca/rp-pr/p2/2022/2022-07-06/html/sor-dors140-eng.html

12.0 PJ/d) respectively. The entire inventory of RNG projects if developed as above could decarbonize nearly half (48%) of current North American grid gas consumption if negative CI's are considered or just 18% if RNG is only seen as carbon neutral.

- **RNG Supply Potentials vs Realism:** Converting biogas into RNG requires onsite or interconnected gas processing capacity. That capacity must extract impurities to yield a marketable RNG gas stream that meets pipeline quality specifications. RNG producing projects will also require pipeline injection points and/or virtual pipeline solutions to move RNG to market. The capital investment and operating costs for these projects can preclude or delay the development of disadvantaged locations and projects. From a standpoint of capital efficiency, the greatest RNG output for the lowest capital investment can likely be found at projects within existing landfills. In fact, some landfills have older biogas-to-power or heat applications. These can be supplanted by new energy transition technologies (i.e., solar) and yield opportunities to redevelop a producing landfill for RNG production.

  Landfill RNG volumes suffer from relatively high carbon intensities in comparison to other forms of RNG. Achievement of net zero performance is not possible with landfill RNG regardless of the mix, cost or volumes procured. Even if a well-funded customer sought to replace all geologic natural gas use with RNG from LFG projects, that customer would not achieve full decarbonization despite the high cost. Despite higher procurement costs, which would be multiples of conventional natural gas, the decarbonization would be only partial. More expense for limited decarbonization potential will likely not be a good formula for regulated utility buyers.

Figure 5.1.2: CI Scores Compared in California LCFS Markets



(Source: CARB 2021 Volume Weighted Averages, annotations by Anew Advisory)

Projects at WWTP can deliver carbon neutral RNG with certified CI scores of zero. That means a client buying WWTP RNG could theoretically achieve net zero performance if all geologic gas was replaced with RNG from WWTP projects. There are likely very few buyers who would seek this option and even fewer project developers that expect a big market populated by these kinds of buyers to develop. Dairy and swine farms are currently the one commercial RNG production option with both powerful decarbonization potentials and sizeable supply scale-up opportunities. In the California LCFS market, RNG gas from swine and dairy projects can be certified with CI pathways in as low as -600 g CO_2e/MJ.

Table 5.1.3: RNG Price and Performance Varies by Feedstock and Production Technology

	CI score CA-GREET, gCO_2e/MJ	Stacked EA Value, $/Dth	Tonne CO_2e reduction/Dth	Decarbonization Impact Price, $/tonne CO_2e
Landfill Gas	40	35.64	0.037	954
Food Waste AD	0	39.23	0.075	520
Dairy Manure AD	-175	54.90	0.242	227
Swine Manure AD	-375	72.81	0.433	168

Source: Anew representations for Argus prices dated 7/20/2022 per Jaffe et al method.

The combustion of one unit of highly potent carbon negative gas can effectively decarbonize the combustion of 7.5 times the volume of regular geologic gas. With such a powerful decarbonization tool, this RNG can be used at a 14% mix rate within geologic natural gas to achieve full decarbonization. This performance is not possible with LFG-derived RNG and it contrasts strongly against the 100% mix rate required for full decarbonization using RNG from WWTG or a more efficiently-produced version of landfill gas RNG with a zero CI. Superior decarbonization properties of swine and dairy gas in the CA LCFS market results from regulator recognition of the value of RNG's avoided emissions.

Despite swine and dairy manure higher prices on a per-energy unit basis, the price per tonne of CO_2e abated, a measure of its performance, is greatly lower than RNG from other LFG and WWTP opportunities. The superior performance translates into more credit generation potential within the LCFS and other CI-aware programs. More credit generation means more market value and financial return shared with the producer. Transportation customers commenting to FortisBC noted this reality, and the comments are summarized by FortisBC in their statement that customers buying RNG on the open market "pay more for RNG with lower carbon-intensity, (yet) the additional credits more than make up the difference."[96]

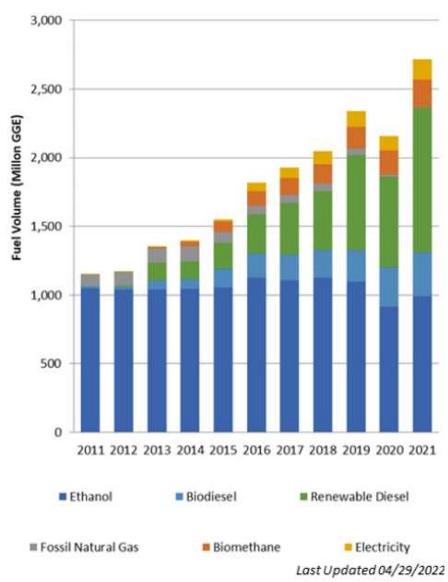
This explains why the average type of RNG used in the LCFS program of California is in the negative range. The unit price for the energy may be high, but that same unit of energy has a very valuable monetizable credit yield. It also has a very low cost and impactful decarbonization performance relative to other partial-decarbonization options with positive CI scores. As utilities seek deep decarbonization with low volume purchase requirements and goals to minimize consumer sticker price shock, RNG projects at swine and dairy farms will likely ramp supply to rise to the occasion.

[96] See pages 255 and 256 of 559, https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf

5.2 Factors Affecting North American RNG Demand

- **Demand in Transportation Compliance Markets:** Alternative fuel demand in California's LCFS marketplace shows the demand growth for RNG amid other competing transportation fuels. Over the last ten years, alternative fuel demand has more than doubled. In the early days of the LCFS program, ethanol and geologic natural gas were the fuel choice options. Demand has dwindled for both as bio and renewable diesel, biomethane, and electricity has taken share and driven demand higher in more recent years.

Figure 5.2.1: California LCFS Program Alternative Fuel Demand Growth



Source: California Air Resources Board

In Ontario and Canada, the same rotation toward higher percentages of RNG in gaseous fuel pools may play. The RNG Coalition commissioned work by Bates and White Economic Consultants showing gas demand in CNG and LNG propelled roadway transportation across North American rising from a base of 995 million gallons of gasoline equivalent (GGE) demand in 2021 to 1056 million GGE in 2025. That is a growth rate of 1.4% on average, compounded annually. The equivalent in dekatherms per day in 2025 is 368,542 Dth/d (0.385 PJ/d). That volume represents several multiples of current North American RNG supply. It is not guaranteed that the mix of transportation gas fuel will supplant geologic or fossil gas entirely, but the California experience may offer a touchstone if voluntary and compliance market programs in aggregate evolve similarly.

- **Demand in "Pre-Compliance" Transportation Markets:** Although its greenhouse gas emission regulations and standards are still evolving, the maritime sector can be seen as a significant "pre-compliance" decarbonization market. Liquefied natural gas, either sourced by geologic or biogenic supplies, is seen by ship builders, owners, and operators as a commercially available marine decarbonization fuel.

Decarbonization mandates are soon to be launched by the United Nation's International Maritime Organization (IMO) for larger maritime vessels operating in international waters. The IMO will in 2023 begin monitoring vessel operations for compliance with new ratings programs around carbon intensity. Other jurisdictions including the EU have additional pre-compliance initiatives underway for maritime traffic in their own jurisdictional waters. Compared to marine distillate fuel which is consumed globally in quantities nearing four million barrels per day or nearly 20 million Dth/d, the use of LNG in gas-fueled engines offers significant reductions in carbon intensity. The use of RNG can further reduce emissions to or below zero depending on RNG mix and the recognition of avoided emissions.

The LNG export industry has long used gas propulsion to move LNG carriers from exporting liquefaction terminals to importing regasification plants around the globe. In recent years, ship builders, owners and operators have adopted gas propulsion for many other classes of maritime vessels. With interests in exceeding the 20% relative decarbonization potential considered possible with LNG fuels, several firms have loaded RNG fuels into marine vessel fuel tanks in order to achieve lower or even zero carbon maritime operations.[97, 98]

Anew to date has completed two such RNG bunkering events in US markets. The latest occurred in Spring 2022 with the launch of a newly constructed Offshore Supply Vessel. Anew provided the bunker fuel supplier with an appropriate volume of swine-based RNG to create a carbon-neutral blend for the vessel's operations in US Gulf Coast waters.[99] RNG bunkering events have occurred elsewhere, especially in the European Union. There, gas-propelled cargo ships, ferries, and cruise liners have bunkered RNG to meet or exceed long-term compliance requirements and voluntary goals.[100]

Multiple other technologies exist for maritime decarbonization and rules are evolving. Yet the magnitude of this industry's potential gas demand and its existing use of RNG require monitoring for its potentially large demands for RNG.

- **Demand in Voluntary Markets:** The methane contained within gas produced and processed to pipeline quality standards is chemically identical to the methane sourced through geologic or other means. However, the release of CO_2 resulting from the combustion of biogenic methane is not seen as a contributor to anthropogenic climate warming. On top of those energy and environmental benefits, RNG projects can capture biogenic methane emissions that would have otherwise off gassed into the climate during the decay of biogenic materials. The ability of RNG projects to capture biogenic methane avoids deleterious methane emission leakage into the atmosphere.

  User groups therefore consider RNG as a drop in replacement fuel for natural gas whose use can reduce anthropogenic warming. It's flexibility and compatibility with existing infrastructure and uses positions RNG as a premium option to reduce CO_2 in the economy.

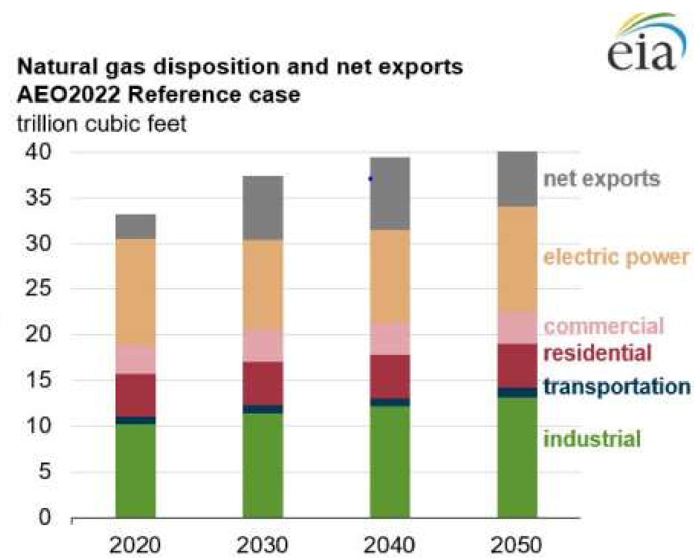
[97] https://pivotallng.com/pivotal-lng-providing-renewable-lng-to-worlds-first-carbon-neutral-platform-supply-vessel/
[98] https://pivotallng.com/jax-lng-and-tote-complete-first-renewable-lng-bunkering-in-the-united-states/
[99]
[100] https://www.biokraft.no/press-release-hurtigruten-partners-with-biokraft-in-record-breaking-biogas-deal/

Other decarbonization options exist today to serve in the energy transition. Fuel switching can be done for multiple end uses. Options include electrification, hydrogen and its potential carriers like ammonia and methanol. Efficiency improvements or demand destruction can also reduce energy use and concomitant carbon emissions.

Little visibility exists into which energy source will gain share, which will lose share, and what the overall market needs for energy will be. While less rigorous than other models, one approach for estimating RNG demand is to take current demand for natural gas as the potential market for RNG if it was available today. The RNG Coalition suggests that the ultimate market for RNG when amply supplied is none other than the then-current market for natural gas.

Utility programs that target all tiers of customer segments (industrial, power, commercial, residential) reflect this thinking inherently. Little end-use natural gas occurs outside of the confines of pipeline delivery. One exception to that rule is the currently non-material gas demand served by virtual pipeline operations (truck delivered CNG or LNG).

Figure 5.2.2: US Gas Demand Forecast by EIA, Annual Energy Outlook 2022 Reference Case



Source: US EIA

For the 2020's, the US EIA projects US aggregated natural gas demand will hold roughly flat with 2021 levels. On a disaggregated basis, the demands within the residential, commercial and power generation sectors fluctuate slightly to net out the noticeable gain in industrial natural gas demand. The EIA forecasts show significant increases in natural gas demand related to producing, pipelining, and compressing rising volumes of geologic gas to serve rising LNG exports that more than double during the decade.

The significant growth drivers in EIA's Annual Outlook forecasts for natural gas demand this decade are the 50% and 13% growth rates in lease + plant fuel in US gas producing fields and in gas consumed to liquefy LNG for export, respectively. Those gains from very small bases were diluted by lesser gains in residential, commercial, and roadway transportation segments. The positive one quadrillion BTU forecasted gain in the industrial space over the decade was offset by a nearly equal negative 1 quadrillion BTU in forecasted demand decline in the electric power sector. All told, US demand is forecast to enter the 2030 timeframe with a gas demand level essentially flat with that of 2021. The forecast shows a peak demand occurring in 2024 at 31,840 million Dth per year (33,631 PJ/y) before sagging modestly and again returning to that level in 2028 before going on a slow decline forward. On a daily basis, that peak rate during this decade represents approximately 87 million Dth/day (91.8 PJ/d).

- **Registry-Listed RNG Certificates and Trading:** Where compliance programs exist, jurisdictional regulators and administers specify how and where the mandated listing, trading, record keeping, and retirement of program credits occurs. The voluntary marketplace has no one registry specified or mandated for use. Third-party independent registries have arisen to serve the role for the voluntary marketplace In the North American RNG marketplace, the M-RETs registry became the place where certifications can be traded for the voluntary marketplace. M-RETs initially was founded to provide a platform for the voluntary registration and trading of Renewable Energy Credits (RECs) in the electric power industry. The broadening and extension of its platform and services into the RNG marketplace was launched on January 1, 2020.

Table 5.2.1: RTC Certificate Attributes Tracked in M-RETS

Account Level	Project Leve	RNG Attributes
Account Holder	Project Name	RTC Serial #
M-RETS ID	Location	Vintage
Account Number	Volume of RTC	Carbon Pathway
	Feedstock	CI Score
	Listed Quantity	Independent Verification

Source: Anew Advisory presentation of M-RETs information

The M-RETS Renewable Thermal Tracking System issues one RTC for each dekatherm of RNG. An RTC specifies details around the production and chain of custody, project level details, and environmental attributes. Importantly, this includes for each RTC include the CI resultant from scientifically validated carbon intensity pathways as developed using Canada's GHGenius model, Argonne National Labs GREET model, or the LCFS lifecycle pathway used by the California Air Resources Board.

When an RNG project is listed on M-RETs, the RTCs are meant to give transparency to buyers as well as those who have oversight of the buyers (e.g. - the utility commissions of regulated distribution utilities with program purchases of green gas). A key service available through M-RETs is an RTC trading platform that affords efficient digital transactions. Digital trading can aid liquidity and volume that ultimately tends to improve market function, price discovery, and growth in both RNG use and production.

Green-E is another pending certification and standard that is being developed by the Center for Resource Solutions. This standard will accept a limited number of pathways and has specific requirements and rules for listing and certification of RNG under the standard. This certification will likely apply to a subset of voluntary RNG types and classes. M-RETs is approved for use in tracking transactions within Canada and the US for Green-E certified RNG, according to current program materials.

- **Enbridge Gas RNG Demand Initiatives to date:** The pilot voluntary RNG purchasing program offered by Enbridge Gas in Ontario is roughly halfway through its 2-year pilot timeline. A more developed offering is available to the customers of Enbridge Gas's affiliated gas distribution utility, Gazifère.[101]

  Enbridge Gas as a corporation is also interested in decarbonizing a broader range of operational activities related to the energy transition.[102] As part of that ambition, the company has set upon goals to reach significant and sustained levels of green gas use to offer long term decarbonization options to customers of its Enbridge Gas distribution utility.

  The trend to direct RNG output to B.C. and other RNG markets that offer high value or long-term contracts will likely continue for the short and mid term. The RNG ambitions of a utility within a regulated service territory will face supply competition from across the continent for the foreseeable future. Gas utilities will likely need to procure RNG from producers wherever they are found on the continent under flexible book and claim delivery procedures that assure greatest logistical efficiency. Given the continental competition, long-term contracts covering large volumes will likely draw the best bids from producers across North America.

  An illustration of these realities can be seen in the procurement plan disclosures by FortisBC.[103] These plans show they procure RNG from projects in jurisdictions across Canada and the U.S., including from within Enbridge Gas's Ontario franchise area. Projects located in B.C. represent less than 30% of the approved procurement contracts, while projects in Ontario represent in excess of 42%.

5.3 Factors Affecting North American RNG Pricing

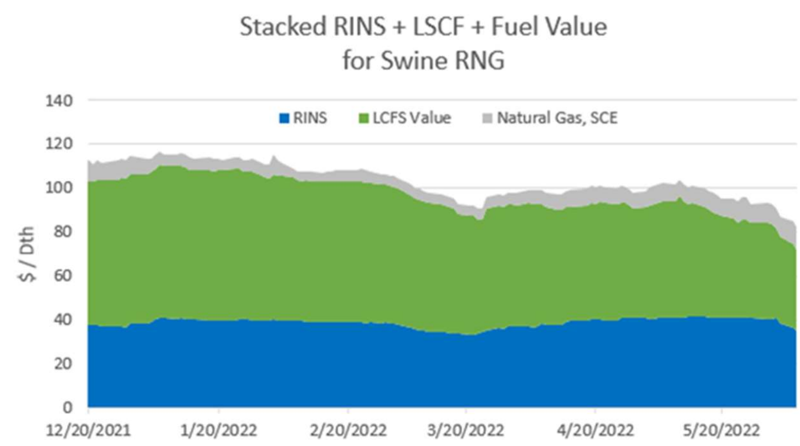
North American RNG prices are set by producers seeking the highest value market on the continent. Spot market prices are higher than long term contract purchases. On a long-term contract basis, costs are typically set closer to a producer's economics. RNG is processed to pipeline specifications and is capable of being injected and moved to any meter on the continent. As a result, the price is fairly uniform when sold on the short-term market except for transportation differentials. Most producers seeking to optimize return on their investments seek pathways to the high value markets created by the fuel standard regulations within State of California for short term sales of RNG. Book and claim mechanisms can allow RNG from any part of the continent to reach and participate in distant markets under multiple existing pathways that spell out delivered RNG carbon intensities and therefore credit value under fuel standard programs.

- **Drivers of Price Volatility~~:~~** In addition to the underlying volatility of the fossil transportation market (crude oil, gasoline, diesel, etc.), there are unique drivers specific to RNG that can affect its value. While natural gas is not yet a popular transportation fuel, its use in heating and power generation set up additional volatility and seasonality through the year. Furthermore, RNG is valued both for its

[101] See [Renewable Natural Gas - Natural Gas, Heating, Furnace Gatineau - Gazifère (gazifere.com)]
[102] https://www.enbridge.com/about-us/our-values/sustainability-goals
[103] Please see Table 6-1 in [DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf (bcuc.com)]

fuel value (in line with geologic natural gas) and for the compliance market value in relevant transportation markets. The most influential transportation markets are in the California Low Carbon Fuels Standard marketplace at the state level, and the U.S. Renewable Fuels Standard at the federal level. The value for RNG is calculated differently in each jurisdiction. Further, the use of RNG in California qualifies for RNG credits under both the state and federal programs. This is the concept of "stacking" or simply adding up the multi-jurisdictional credit values for a volume of RNG. To these credit values, the energy fuel value is added. The price for RNG thereby effectively rolls up the economic fundamentals and market price vicissitudes for natural gas, transportation fuels, state and federal decarbonization compliance programs. Therefore, there is significant volatility in spot RNG indicative values as built up from daily prices as show in the following figure.

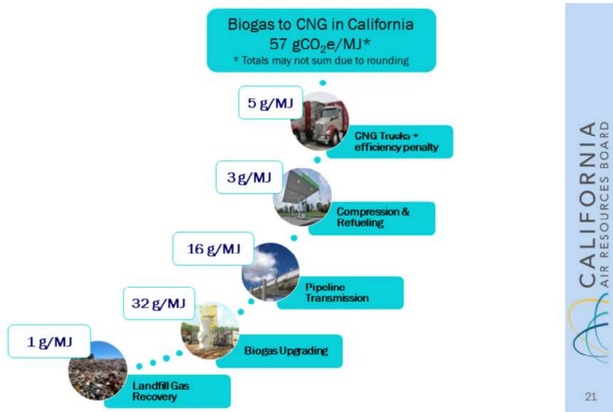
FIGURE 5.3.1: Price Volatility of RINS, LCFS and Natural Gas Fuel Values



Source: Anew Advisory representations of Argus 07/20/2022 price per Jaffe et al method

- **RNG Types by CI Score:**—Carbon Intensity of RNG is fundamentally driven by the RNG production process, starting with supply. Biogenic and cellulosic materials within land fills off-gas methane at vastly different rates than the organic solids in wastewater treatment plants or in the wet agricultural waste manure handling operations. As such, the supply and production of RNG is the largest contributor to RNG CI. All forms of biogenic methane must also be processed to remove sufficient non-methane constituents and contaminants to meet pipeline quality specifications. These contaminants can include mercury in landfills. More commonly, CO_2 is found along with methane because of organic matter decomposition and must be reduced via processing to pipeline specifications. The establishment of an RNG CI also includes adjustments for the CO_2 impact of transportation, distribution, and consumption.

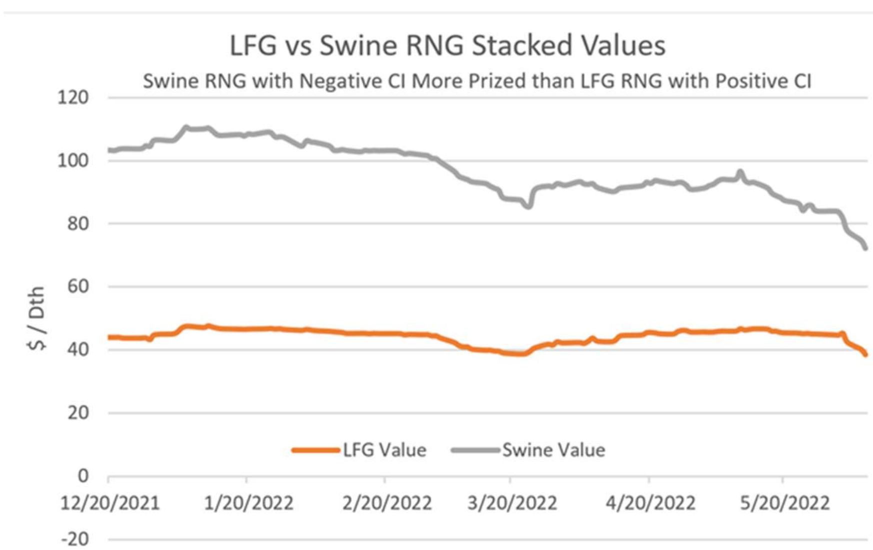
FIGURE 5.3.2: Building up CI Scores for Landfill Gas in California LCFS Markets



Source: California Air Resources Board

- **Impact of RNG CI on Prices:** The goal of LCFS programs across North America, including those in B.C. and California, is to reduce carbon in transportation by reducing the embodiment of CO_2 within each unit of delivered transportation fuel. CI is therefore measured in grams of embodied CO_2 equivalent per megajoule of contained and delivered energy. Credits are awarded for the utility of a given fuel to be supplied to the market with lower CI than a reference baseline fuel. The fuels with lower (or even more negative) certified CI's will generate more credits and more value. Carbon negative fuels like RNG from wet manure producing facilities are highly valuable in LCFS programs. Swine and Dairy derived RNG offers not only potency in reducing transportation CO_2 emissions, but also can do more at a lower cost per tonne of reduced carbon and with less fuel volume introduced into the fuel mix.

FIGURE 5.3.3: Carbon Intensity and Price Performance of RNG by Type



Source: Anew Advisory representations of Argus prices through 07/20/2022 per Jaffe et al method

- **The Primacy of the California LCFS to US RFS Markets:** Because the roadway transportation market is one of the most difficult to decarbonize, regulatory programs have installed relatively lavish incentives to pull renewable supply of ever-cleaner fuels into transportation markets. California has been on the forefront of this trend. The LCFS crediting program is well established, well regulated, and strongly incentivizes certified production and use of RNG. Included within the California LCFS program structure for RNG is the recognition of the beneficial nature of avoiding methane off-gassing from biogenic material decomposition. RNG producers with facilities that prevent the release of more methane are rewarded with lower or even negative CI scores that add value and pricing power. Conversely, the federal RPS and its RIN price value only the fact that the average type of cellulosic RNG has at least 60% reduction of carbon intensity versus its reference. Credits are granted to a fuel that passes the threshold. No extra credit is given under the RIN program for extra decarbonization potency beyond that threshold. As such, the highest value portion of stacked US RNG prices have typically been seen in CI driven markets like California. That in turn pulls more supply from producers of the most potent types of concentrated carbon negative RNG into the marketplace.

- **How RNG Prices Stack**: As previously noted, the concept of "stacking" is the act of adding up any simultaneous values that a molecule of RNG can realize. Fuel buyers within state jurisdictional transportation programs are also subject to federal fuel rules, so the compliance market price for RNG includes both state and federal clean fuel values. In California, RNG values are driven by the LCFS credit price and California's CI rating for the fuel as determined by approved and modeled pathways by feedstock and project type. In the US program, the RFS value is dependent on the value of the attached Renewable Identification Number or RIN credit that the program allows. On top of these values, RNG buyers also must pay the producer for the energy content of the fuel. Adding the three values (LCFS program, RIN value, and Fuel value) on a consistent unit basis yields the stacked value (refer to Figure 5.3.1). California's compliance-driven transportation fuels market is currently the highest value market in the US for RNG because it stacks fossil, federal and state value.

- **How Voluntary Buyers Must Bid for Supply:** In theory, because book and claim methods for delivery of natural gas and RNG exist across North America, producers of RNG can effectively reap gross California revenues from nearly anywhere. These prices are the stacked sum of RINs, LCFS, and fuel value less pipeline transportation charges. This means buyers of RNG in North America are effectively bidding against fuel retailers and roadway fuel consumers in transportation markets. The willingness to pay for RNG by a voluntary buyer must effectively be at or near the compliance -driven fuel prices in the transportation marketplace. Because of the multi-jurisdictional stacked fuel prices, a seller of RNG in Michigan, for example, has a target price close to the fuel and fuel credit prices realizable in California. The stacked RNG value in transportation compliance markets (fuel value plus the value for RINs and LCFS credits) is effectively the opportunity cost that a seller in Michigan would forego if a project's RNG output was instead purchased by a voluntary buyer in Michigan. Buyers outside of California LCFS transportation markets can and do structure supply agreements at lower than stacked transportation spot pricing with producers. The procurement agreements of FortisBC, all subject to a price maximum of CAD $31/GJ, show such success in contracting long-term supply from projects in three Canadian provinces and three U.S. states.[104] Producers seek to insulate their revenues and cash

[104] DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf (bcuc.com)

flows from volatility by structuring long term unit price and volume contractual agreements.[105] The levers to realize lower prices for voluntary and non-transportation buyers include committing to longer term, higher volume contracts. We also note that voluntary buyers can procure RNG from a broader supply pool. Broadening of the RNG supply pool can be achieved by sourcing RNG from projects with production pathways that do not qualify for the highest value uses in transportation compliance program. For example, the California LCFS program does not have a pathway for crediting of RNG made with poultry litter[106], so RINs value bundled with fossil fuel value is likely the pricing benchmark that voluntary buyers of this type of RNG can target. Niche producers of poultry-based RNG include Clean Energy Biofuels and Bioenergy Devco.[107]

[105] See Kinder Morgan Inc. corporate presentation of August 10, 2022. https://s24.q4cdn.com/126708163/files/doc_presentations/2022/08/August-2022_vF1_Including-NANR.pdf
[106] See CARB LCFS pathway table spreadsheet at https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities
[107] https://www.bioenergydevco.com/feedstocks/ and https://cleanbayrenewables.com/technology/

APPENDIX A: Utility RNG Programs Summary

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
SoCalGas & SDG&E	California	RNG	California requires Natural Gas Utilities to supply 12% of 2020 core gas demand with RNG by 2030. LDCs must procure RNG amounting to 8 MMT of organic waste diversion by 2025.	Voluntary	- As approved, Residential customers will be able to select a fixed dollar amount per month ($10, $25, or $50) for the purchase of renewable natural gas. - Commercial customers will be able to select a fixed dollar amount per month or select a percentage of their consumption for the purchase of renewable natural gas, up to 100%.	SoCalGas estimates that the RNG Tariff program will incur marketing costs of approximately $330,000 over the first 5 years. SDG&E estimates the marketing costs over the first 5 years to be approximately $200,000. The residential customer program has a minimum commitment of 1 year. The non-residential customer program has a minimum commitment of 2 years. SoCalGas estimates the RNG Tariff program will incur approximately $90,000 in program marketing costs during the first year of the program and approximately $60,000 annually thereafter SDG&E estimates the RNG Tariff program will incur approximately $40,000 in program marketing costs annually. RNG supply will come through contracts with marketers who carry a portfolio of RNG supplies or contracts directly with biogas producers/developers If there are any shortages in supply, the supply will be made up with surplus supply or with purchases in future months In 2021, 14 billion cubic feet of RNG was distributed via their pipeline system In 2020 SoCalGas had approximately 5.6 M residential customers and sold roughly 229M Mcf of NG

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Puget Sound Energy	Washington	RNG and Offsets	Washington requires gas utilities to offer, by tariff, voluntary RNG service for customers with participation limited by availability of supply. Customer charge for RNG cannot be more than 5% of the amount charged to retail customers for natural gas.	Voluntary	- PSE offers both RNG and offsets to customers - Customers can choose to replace part of their NG with RNG. RNG increments start at $5/month. - Customers can also choose to purchase 3rd party verified offsets. Offsets start at $3/month.	PSE's RNG is produced by Klickitat Public Utility District at the H.W. Hill Renewable Natural Gas facility in Roosevelt, Washington. More than 1200 customers have enrolled since December 2021. In 2020 PSE had approximately 792,000 customers and sold roughly 59M Mcf of NG Participating customer revenue will be used to fund the ongoing costs of RNG purchases, administration, marketing, and overhead. RNG accounts for 0.5% of PSE's annual RNG program, and will potentially reach 3.5% by 2024

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Dominion Energy	Utah	RNG and Offsets	Voluntary	Voluntary	- Dominion offers two voluntary programs in Utah and Idaho called CarbonRight and GreenTherm. As part of GreenTherm customers can choose to add a number of RNG blocks that represent RNG green attributes to their monthly bill - Each block is $5 per month which is equivalent to 0.5 dekatherms, and customers can chose to buy as many blocks as they wish. -The CarbonRight program began in March 2022 and allows customers to choose to add $5 blocks a month to offset a typical home's emissions from natural gas, or business footprint. The program is open to residential, business or government. Each block is equal to 0.3533 mt CO2e which would equate to	GreenTherm: In 2020 a total of 10,518 blocks were sold and the associated marketing costs were $4,774, for a total program expense to admin ratio of 19% The total customer count was 1,165 for the RNG program. In 2021, 38,297 blocks were sold, the total administration costs were $8,078 for a total program expense to admin ration of 4% -The GreenTherm program seeks to purchase RNG environmental attributes from local sources; however, if Dominion is unable to find RNG from local sources, they will be purchased where available. -The funds from the blocks would go to 1) purchase of RNG, 2) administration of program, 3) any leftover will fund qualifying initiatives. The company estimated it would incur $265,000 in administration costs for the initial set up of the program, and $300,000 in the following year. -RNG would be procured through RFPs to vendors, producers, and suppliers to get the most favorable pricing CarbonRight:-The CarbonRight program currently uses two landfill gas capture/combustion offset programs it uses (one in Utah and one in Missouri), and a forest carbon project in Minnesota. These landfill offsets projects are registered under the Climate Action Reserve, and the forest carbon project is registered under the American Carbon Registry. -As a condition of the approval of the program, Dominion needs to maintain information about the selected offset programs on its website

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
					approximately 80 dekatherms of natural gas per year if one block was purchased per month for 12 months. -To obtain the offset projects, and RFP was sent out to select a portfolio of projects for the program to get known projects and costs	-Non-program participants will not bear any of the cost of the program. All costs associated with the project application were redacted from the file In 2020, Dominion had approximately 371K residential customers and has sold 12M Mcf of natural gas

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
DTE Energy	Michigan	RNG and Offsets	Voluntary	Voluntary	- CleanVision Natural Gas Balance program uses a mix of 95% carbon offsets and 5% RNG to allow customers to offset a portion or all of the emissions associated with their monthly natural gas use in the following amounts and costs: 25% ($4); 50% ($8); 75% ($12); 100% ($16)	Approximately 2800 customers opted into DTE's RNG program in first 6 months after its 2021 launch. By 9 months later, the customer count was 5000, and 12 months later was at 6500. In DTE's latest update in June 2022, they mention that the RNG program enrollment has reached 6,500 customers. In 2020 DTE had approximately 1.1 M residential customers and sold roughly 98 M Mcf of residential gas. More than 5,000 DTE Gas residential and small business customers enrolled in the program As a part of their next steps, DTE will start a companion program for commercial and industrial customers

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Nicor Gas	Illinois	RNG and Offsets	Voluntary	Voluntary	- Nicor Gas filed a rate request with the Illinois Commerce Commission, which includes a proposal to offer customers a new pilot program called TotalGreen. - Offers customers voluntary program to offset consumption with 5-20% RNG and remaining as carbon offsets or 0.5% RNG and 99.5% carbon offsets to test consumer price preferences. -There will be no physical delivery of RNG, but the environmental attributes will be purchased until such time that the market develops further and physical delivery can be achieved -Currently the program is being offered at cost, with no markups, and only participating customers will bear the	In 2020 Nicor Gas had 1.9M residential customers and sold approximately 195 M Mcf of residential gas. They currently have an RNG interconnection service pilot program for provision of an interconnection service between a renewable gas production facility and existing Nicor gas transmission or distribution facilities. Nicor investment for this program is limited to in aggregate up to $16 M, with each renewable gas production facility limited to $3.2 M. Nicor will negotiate for a set number of environmental attributes to be transferred from the developer to the pipeline owner, and use these attributes to offset GHG emissions associated with its broader portfolio. For the Total Green Program, criticism has been around not enough information regarding transparency with respect to the source, type of project, additionality of offsets and RNG credits and ongoing accountability to ensure offsets and RNG sources have a tangible connection to Nicor's system and local resources. There was also criticism that the program asserts it would result in a net-zero carbon footprint for natural gas usage but customers only purchase RNG and offsets equivalent to their on-site and end-use consumption, without accounting for upstream emissions. Nicor will not estimate and integrate upstream emissions in the program, and agreed to disclose in program materials that this program was only addressing a consumers GHG emissions and does not include lifecycle emissions that occur upstream. Interveners felt it was important to let the customers

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
					cost. There is no risk to consumers. -Much of the filing in docket P2021-0098 was considered confidential information and not given publicly.	know where the offsets were being purchased from, and what the project was so they are understanding what they are purchasing. It was indicated that projects should be in proximity to Nicor gas service territory when selecting offset projects.

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Summit Utilities	Maine	RNG	Maine requires the PUC to allow utility to use RNG for no more than 2% of the gas it supplies to its customers starting in 2022 and to allow a utility to use an additional 2% annually thereafter. Utility may include the costs of RNG in its cost-of-gas adjustment rate.	Voluntary	- Customers enrolling in Summit's program may elect to match 10 to 100 percent of the average annual usage of similar customers with RNG attributes. The quantity of RNG attributes, and a flat rate monthly fee, will be added and shown on enrolled customers' bills.	

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Vermont Gas Systems	Vermont	RNG and Offsets	Voluntary	Voluntary	- VGS offers customers two options for purchasing renewable attributes of RNG. Locally Sourced RNG specifically supports local supplies of RNG by acquiring the renewable attributes from Vermont projects, like the Goodrich Farm in Addison County. Blended RNG supports supply from all of VGS's RNG sources at a lower price per 100 cubic feet (CCF). -RNG supply is fixed price, term contracts, keeping costs relatively stable over time	- Currently, the Blended RNG Adder is $1.1436 per CCF and the Locally Sourced RNG Adder is $1.5098 per CCF This is the same for both residential and commercial customers. -In the event there is inadequate supply of RNG, the Company may meet the customer's RNG option by purchasing equivalent carbon offsets. If carbon offsets are not available, the Company will contribute equivalent revenue to the Clean Energy Development Fund. If this circumstance persists for longer than 30 days, the Company will notify all RNG Adder customers. -Vermont Gas intends to supply 20% of its supply mix for retail customers with RNG by 2030. The company proposed to add approximately 2% RNG per year into its portfolio. -the initial program proposal suggested a 12 month true up window that will allow RNG oversupply to be sold to customers if necessary and any undersupply to be met through additional RNG supply contracts or other means -VGS is looking at a way they can separate the attribute from the molecule such that they can bank the attribute, match them with sales, and spread out rate impacts over time -for any excess RNG not sold under the program, Vermont Gas may market the carbon offsets or any of the available credits relating to RNG and any revenues generated will be used to offset RNG costs. Vermont Gas will seek incentives such as the RFS RINS -RNG pricing took into account the carbon pricing at $100/ton

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
						-The average level for residential customers in the program is 40%, - since beginning to offer the program approximately 105,000 mcf of natural gas have been displaced. Anticipating in 2021 another 120,000 mcf/year -this includes voluntary annual usage of 40,000 mcf/year, the firm portfolio carrying 65,000 mcf/year, and Vermont Gas using 105,000 mcf/year for internal use.

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Avista - Idaho/Washington	Idaho, Washington	RNG	Washington requires gas utilities to offer, by tariff, voluntary RNG service for customers with participation limited by availability of supply. Customer charge for RNG cannot be more than 5% of amount charged to retail customers for natural gas.	Voluntary	The company will offer customers the ability to purchase blocks of RNG at a price of $5 per block of RNG environmental attributes, equivalent to 1.5 therms of RNG	Customers can start or stop this program at any time but it is subject to supplies lasting The costs will be covered by program participants and contained within the RNG program, with costs tracked separately. The company will use M-RETS to track the environmental attribute The RNG is being acquired from Puget Sound Energy
Fortis BC	British Colombia	RNG	The CleanBC plan calls for a minimum of 15% of natural gas be provided from renewable sources by 2030.	Hybrid	- Fortis BC allows natural gas customers to designate 5, 10, 25, 50, 100 percent of their natural gas use as RNG. - Fortis is seeking to modify its existing program, and expects all customers to receive a one percent RNG blend starting in 2024, and will increase over time to meet provincial clean energy targets -in the proposed program, all new	Fortis obtains their RNG supply from a range of suppliers such as farms, landfills, and wastewater treatment plants In 2019, the RNG demand exceeded the RNG supply and resulted in Fortis putting a temporary pause on the program. At this time there were 10,000 customer subscribed to the program The program was reopened in 2021 and still had continuing demand as there were approximately 350 customers on the waitlist At the start of the program the customer education and awareness expenditures were expected to be in the range of $300K per annum, after reopening the program with increased demand the expenditures are expected to be in the range of $340K per annum Fortis is aiming to have a RNG supply of 3.9M GJ in

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
					residential connections will be serviced with 100% RNG and they will continue to offer a voluntary program for existing sales customers	2022 Customers will pay a rate of $13.808/GJ for the RNG or $14.568/dekatherm
Energir	Quebec	RNG	In Québec, regulations require that the portion of renewable natural gas distributed in the gas system be 5% by 2025. This portion may be increased to 10% by 2030.	Hybrid	- Energir allows customers to convert up to 10, 30, or 100 percent of their natural gas to RNG for a cost of approximately $4.50, $13.50, or $45.50 respectively.	

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Gazifère	Quebec	RNG	In Québec, regulations require that the proportion of renewable natural gas distributed in the gas system be 5% by 2025. This proportion may be increased to 10% by 2030.	Voluntary	- Gazifère has a program to allow customers to add RNG consumption to their NG - Customers can choose their consumption percentage: 1%, 5%, 10%, or 100% - RNG rate: 54.50 cents/m3	RNG supply to a customer is only authorized if it is operationally feasible for the distributor to supply the customer with RNG over the course of a year If it is not operationally feasible, the customer will be placed on a waiting list. In 2022, 1% of the natural gas that Gazifère distributes is RNG They are aiming to have 5% RNG in their natural gas supply by 2025.
Southwest Gas Corp -Arizona	Arizona	RNG	Mandatory	Mandatory	1% of sales would be RNG by 2025, 2% by 2030 and 3% by 2025.	Southwest has had successful programs in Nevada and California. This program was rejected in 2020 because it was felt the environmental attributes of RNG couldn't be certified at that time, nor monetized. It was also rejected because it was felt the market was not fully developed enough for RNG for any cost certainties, and that the cost of RNG was too great compared to conventional NG. A workshop was to be conducted in 2020 to explore the role of RNG in Arizona.

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Black Hills Gas	Currently seeking approval in Colorado, but will soon submit applications with similar programs in Kansas, Nebraska, Arizona, Iowa, and Wyoming by 2023.	RNG and Offsets	Voluntary	Voluntary	The program provides residential or small commercial sales customers the option to purchase blocks which equate to approximately 25% (20.5 therms) of the average residential customer each, up to 100% of their use. For each block the company will procure RNG environmental attributes and carbon offsets, currently estimated at $5.00 USD per block. The product offsets 99% of CO2 emissions through carbon offset credits and 1% of CO2 through RNG environmental attributes. The program will be funded by participants only, and not passed on to non-customers. Blackhills has 180,000 residential customers, 15,000 small commercial customers. by the end of the pilot,	The pilot program is proposed to start Jan 2023, for 4 years, with plans to evaluate on a yearly basis. Fees will be used to cover environmental attributes, ongoing administration, marketing, and overhead costs. Total marketing costs range from $87,500 to $119,750 per year. Administration costs were estimated at approximately $50,000 per year, and IT expenses at $4500 per year. -the company has allocated $15,000 per year for compliance, environmental attribute and carbon offset credit verification and certification, and annual program audits The company is asking for a differed accounting mechanism to give the company an opportunity to defer expense in the year incurred, with the opportunity to recover those deferred costs in the future as program participation increases. In the early years of the pilot the anticipated expenses associated with upfront marketing costs in acquiring new participants are greater than the anticipated revenues due to low initial participation, resulting in expenses exceeding revenue. In subsequent years, increased enrollees could generate revenue in excess of program expenses, creating a regulatory liability. If the program becomes over-collected, the company will use the excess revenues to benefit program participants -by either acquiring more RNG and/or higher premium carbon offsets which would increase the CO2 emissions offset with each block enrolled. -All program costs will be accounted for separately from conventional gas supply including commodity and upstream costs -since RNG is not being offered as

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
					the company anticipates approximately 2900 participants. -Local RNG projects will be sourced to the extent possible -estimated cost through the pilot is $22/MMBtu for RNG, and will be transferred through the M-RETs system, and using the Green-E renewable fuel standard as possible	part of its supply mix, the RNG program costs will be accounted for separately. -the company expects to break even by 2027 once the pilot is complete, and due to consecutive under recoveries from 2023-2026, the cumulative program costs become fully recovered by 2031. -program budget also accounts for a 3rd party audit each year -the program is proactively anticipated the needs of the Senate Bill 21-264 Clean Heat bill that require gas distribution utilities to achieve a 4% reduction in GHG emissions compared to a 2015 baseline by 2025, and a 22% reduction by 2030, of which 1% and 5% of these reductions in 2025 and 2030 respectively can be from recovered methane

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Consumer Energy	Michigan	Offsets	Voluntary	Voluntary	-Participants can offset from 10-100% of the carbon emitted from natural gas consumption -open to residential and commercial businesses -offsets are focused on Michigan forests, but not limited to this	This program has not yet been approved.
NW Natural	Oregon	Offsets	Oregon Gov. Kate Brown recently signed SB 98 into law. The bill sets voluntary renewable natural gas (RNG) goals for the state's natural gas utilities, creating a path for RNG to become an increasing part of Oregon's energy supply.	Voluntary	- Residential customers choose either the Average Home option for \$5.50 a month or the Climate Neutral option for about 10.5 cents more per therm used each month. - Business customer enrollment options start at \$10.00 a month.	- NW Natural has signed agreements with options to purchase or develop RNG totaling about 3% of their current Oregon supply

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Columbia Gas	Maryland	RNG and Offsets	Voluntary	Voluntary	Columbia Gas is proposing a five-year RNG pilot - the Green Path Rider. Under the voluntary program CGM will purchase RNG, environmental attributes and carbon. Will match the customer's election of either a 100% reduction or a 50% reduction in emissions. Customers opting into the Green Path Rider will be charged an additional fee per therm that reflects the cost of the RNG environmental attributes and carbon offsets. The program would be offered to all residential and general service customers that are not in arrears.	

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Liberty Utilities	Massachusett s	RNG	Voluntary	Voluntary	Liberty Gas will offer customers a program where they can choose between 25%, 50%, 75% and 100% of RNG for their gas use.	Liberties Gas has approximately 60,000 customers in Massachusetts -the company has a 20 year contract with an RNG facility at the Fall River Landfill, and Liberty has the exclusive right to purchase from the facility, and the facility will be obligated to sell and delivery exclusively to the Liberty the annual minimum/maximum volumes ranging from 84,458 dekatherms to 196,796 dekatherms per year up to a maximum supply of 168,917 dekatherms to 281,137 dekatherms . -the RNG is being delivered at a fixed cost of $9.25 per dekatherm, increased by 2% annually, to a final price of $13.48 per dekatherm. -in the event customers do not purchase RNG in sufficient volumes to utilize the amount required under the RNG contract, the company would use the RNG it has procured to provide gas service to its customers. -customers would enroll in the program for a 1 year commitment period -during the first two years of supply, the company has the option to purchase all the environmental attributes for the duration of the term for a fixed cost of $25/MMBTU. -this program was filed in March 2022, and has not been approved yet

APPENDIX B: Anew Qualifications

Anew Advisory Services, LLC is part of Anew, LLC which was formed by the recent merger of Element Markets and Bluesource under the ownership of the TPG Rise fund. The merger was driven by the realization of the complementarity between the deep expertise of the two companies. Anew has a combined 30+ years of experience developing more than 350 projects across 20 project types across all of North America, which to date, have yielded 180 million tonnes of verified greenhouse gas emissions addressed. Our mission is to make the highest and best use of the skills, capabilities, experiences and influence we possess to enable the greatest positive impact on climate. Our values of integrity, trust, creativity, and hope anchor our leadership position in both compliance and voluntary environmental markets, and as a key partner to clients pursuing scalable decarbonization strategies.

Anew’s Renewable Natural Gas Expertise:

We leverage a dominant market position in ultra-low CI RNG, regulatory expertise, and relationships with marquee clients in the utility and transportation fuel sectors. Our Renewable Natural Gas team partners with farmers, landfill operators and wastewater treatment plants to generate renewable fuel, register it, and bring it to the market for utilities, fleet operators and voluntary buyers seeking to capture the benefits of cleaner energy. Anew is the largest volume independent marketer of RNG in North America. The amounts of RNG transacted by Anew have displaced 240,000,000 diesel gallons equivalent. Anew is active on the regulatory side as well as in operations and marketing. Anew has developed more than 35 active RFS or LCFS pathways for alternative transportation fuels. Additionally, Anew has been instrumental in leading Green-e to form new Thermal REC standard for RNG. Our in-house marketing services provide registration, credit generation, program compliance and sales of RINs and LCFS credits across a portfolio of demand side buyers. Along with providing long-term offtake agreements for large scale producers of RNG, Anew has become the recognized leader in bringing into the market highly potent ultra-low carbon intensity (“CI”) RNG fuels.

Anew’s Combined Approaches to Full Scope Emissions:

Anew has served compliance and voluntary users with renewable natural gas to offer a direct path to Scope 1 reductions by switching to RNG from natural gas consumption. Anew has also begun offering RNG paired with carbon offsets under its innovative Renew(TM) offering to create a carbon neutral footprint for natural gas use. The turnkey features of the Renew offering include the design of an off-the-shelf product that relieves decision paralysis. Renew is affordable and customizable in that a customer can change the blend rate of products to flexibly match specific climate goals and customer budget realities. The product is certified and leverages trusted 3rd parties to track and certify commodities while also easing administrative burden. Provides direct path to Scope 1 reductions. Anew currently has an inventory of over two million dekatherms of RNG listed on MRETS to support Renew demand.

Anew’s Hydrogen Capabilities:

Anew's proprietary hydrogen business model combines solar power, RNG, and on-site steam methane reformation to produce and dispense clean hydrogen, while preserving optionality to move to electrolysis. Our experience is based on building Hydrogen Refueling Infrastructure (HRI) pathways in the rapidly expanding California hydrogen market. We are actively engaging with fleet owners and OEMs to develop hydrogen consuming solutions to meet their off-road and on-road needs and simultaneously helping our utility customers to explore and develop innovative strategies to participate and propel the hydrogen economy.

To help demonstrate the important role that RNG will play as part of a diversified energy future for the province, Enbridge Gas sought letters of support from RNG Producers to file as part of Phase 2 Evidence. These letters are included in this Attachment, following this cover page.

Enbridge Gas provided the following information for producers to use as a base for the letter. Some respondents replied using the original inquiry from Enbridge Gas on Enbridge Gas's letterhead, and others responded using their own letterhead.

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

This Rate Case is currently active in front of the OEB with an expected decision by the OEB potentially delivered in mid-2024 (the "**Decision**"). If approved on this schedule, Enbridge Gas will begin procuring RNG from the market, seeking first delivery in 2025. In alignment with Enbridge Gas' Gas Supply Planning Principles, Enbridge Gas would be seeking reliable, secure, and cost-effective supply from a diverse range of suppliers and with diverse contract terms. Enbridge Gas would run a competitive process (the "**Procurement Process**") to seek contracts for procurement of RNG to meet these targets upon a favourable Decision in 2024.

Through this letter, Enbridge Gas is actively requesting information from you as a RNG producer as follows:

(Company Name) produces/has intention to produce RNG from (RNG Source ie. Wastewater, landfill, etc.) at (Production Location). (Company Name) produces xx GJ of renewable natural gas per year with plans to increase to xx GJ by the year 20xx.

Section on how Enbridge purchasing RNG will benefit your company or any organizational impact statements you want to make (Write as much or as little as you would like)

(Company Name) would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

To whom it may concern:

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

This Rate Case is currently active in front of the OEB with an expected decision by the OEB potentially delivered in mid-2024 (the "**Decision**"). If approved on this schedule, Enbridge Gas will begin procuring RNG from the market, seeking first delivery in 2025. In alignment with Enbridge Gas' Gas Supply Planning Principles, Enbridge Gas would be seeking reliable, secure, and cost-effective supply from a diverse range of suppliers and with diverse contract terms. Enbridge Gas would run a competitive process (the "**Procurement Process**") to seek contracts for procurement of RNG to meet these targets upon a favourable Decision in 2024.

Through this letter, Enbridge Gas is actively requesting information from you as a RNG producer as follows:

Grow the Energy Circle Ltd (GrowTEC) is an on-farm biogas facility that produces RNG from manure (over 50%, culls from our potato operation, food process organic waste and other landfill diverted organics. GrowTEC produces over 60,000 GJ of RNG yearly with plans to increase to 140,000 GJ/ye by 2026.

GrowTEC is a bioenergy venture by the fourth generation Perry Family Farm that is a model of rural economic development, decentralized energy generation, value-adding agriculture, and circular economy principles.

Enbridge Gas's commitment to RNG aligns with our goals of value-adding agriculture while integrating ag and decarbonized energy. It is noteworthy that our primary agricultural customers, including major players like PepsiCo, Frito Lay, McCain, and Cavendish, are increasingly interested in decarbonizing their supply chains, making RNG an integral component of their sustainability strategies. Recent discussions have included PepsiCo's interest in purchasing RNG from our facility and other we are partnered with in Ontario.

Enbridge Gas' efforts to advocate for the inclusion of RNG in Canada's energy future has the potential to play a crucial role in advancing the goals of GHG and methane reduction on a broader scale for sustainability across Canada's agricultural sector. RNG is more efficient and more economically attractive due to the growing global demand for low carbon intensity fuels. RNG can be transported using existing natural gas infrastructure for use as building space heat/hot water, industrial process heat, electricity generation, and transportation.

Renewable Natural Gas holds significant promise for Canada's energy landscape. It presents a remarkable opportunity for rural economic development by promoting the growth of local biogas and agricultural waste-to-energy projects. The development of RNG infrastructure and production facilities can create jobs in rural areas, providing new economic opportunities while also contributing to the diversification of rural economies.

Decentralized energy generation is another compelling benefit of RNG. By producing renewable natural gas locally, we can reduce our dependence on centralized fossil fuel sources and enhance energy security while utilizing existing natural gas infrastructure. This decentralization can strengthen local communities by allowing them to harness their own energy resources and become more self-reliant.

Moreover, RNG offers the potential for value-adding agriculture, an essential component of a sustainable agricultural sector. Farmers and agricultural producers can benefit from RNG projects that utilize organic waste materials, such as crop residues and livestock manure, to produce renewable natural gas. This not only helps manage waste streams but also provides an additional revenue source for farmers, enhancing the viability of agricultural operations.

Enbridge Gas's initiative to promote RNG is not only commendable but also highly replicable across Canada's agricultural sector. By demonstrating the viability of RNG and supporting its integration into the energy mix, Enbridge Gas paves the way for other regions and communities to follow suit, fostering a sustainable energy model nationwide.

In conclusion, I fully endorse Enbridge Gas's file to the regulatory proceeding and its commitment to showcasing the vital role that renewable natural gas will play in Canada's diversified energy future. RNG offers a win-win solution, delivering economic growth, decentralized energy production, value to agriculture, and circular economy principles, all while meeting the evolving sustainability demands of major agricultural customers.

GrowTEC would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Date: September 8, 2023

Signed:

Chris Perry (he/him)

Perry Family Farm *(CEO)*

Grow the Energy Circle Ltd. *(Founder / Owner)*

Box 210 Coaldale, AB, Canada T1M 1M3

email: ckpfarms@hotmail.com

cell. 403-634-2426

www.perryfarm.ca

andion

650 – 625 Howe Street
Vancouver, British Columbia
Canada V6C2T6

September 7, 2023

Enbridge Gas
50 Kell Drive North
Chatham, Ontario
Canada N7M 5M1

Re: Enbridge Gas's application to the Ontario Energy Board for approval of a low-carbon energy procurement enabling Enbridge Gas to procure up to 1% of its forecast gas supply purchases as low carbon energy – primarily in the form of renewable natural gas.

This letter is in support of Enbridge Gas's application to the Ontario Energy Board regarding the procurement of renewable natural gas.

Andion North America Ltd. has the intention to produce RNG from Organic Food Waste in multiple regions in British Colombia, and from manure at various locations in Alberta. Andion plans to produce 1,200,000 GJ/year of RNG by 2026 increasing to 2,600,000 GJ/year by 2028.

The value of having more choice in offtake partners is beneficial not only to Andion, but also to the Canadian farmers, First Nations and other local partners that work with us to produce RNG.

Andion would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favourable decision in the Rate Case.

Sincerely,

F. Phillip Abrary
President & CEO
Andion North America Ltd.

GENERATE UPCYCLE

To whom it may concern:

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

This Rate Case is currently active in front of the OEB with an expected decision by the OEB potentially delivered in mid-2024 (the "**Decision**"). If approved on this schedule, Enbridge Gas will begin procuring RNG from the market, seeking first delivery in 2025. In alignment with Enbridge Gas' Gas Supply Planning Principles, Enbridge Gas would be seeking reliable, secure, and cost-effective supply from a diverse range of suppliers and with diverse contract terms. Enbridge Gas would run a competitive process (the "**Procurement Process**") to seek contracts for procurement of RNG to meet these targets upon a favourable Decision in 2024.

Through this letter, Enbridge Gas is actively requesting information from you as a RNG producer as follows:

Generate Upcycle produces RNG from food waste in London, ON. Generate Upcycle produces approximately 225,000 GJs of RNG per year with plans to increase to 400,000 GJs by the year 2024, and 600,000 GJs by 2025.

The proposed low-carbon energy procurement outlined in Enbridge Gas's 2024 Rate Case represents a pivotal opportunity for Generate Upcycle. If approved, this initiative aligns directly with our ongoing mission to transition towards a more sustainable energy future by producing RNG from food waste. The prospect of Enbridge Gas seeking to procure up to 1% of its forecast gas supply purchases as low-carbon energy, primarily RNG, in 2025 amplifies the market potential for our RNG production, and their planned increment in purchases by 4% annually until 2028 further augments this potential.

Furthermore, as we are set to significantly ramp up our RNG production, reaching 400,000 GJs by 2024 and 600,000 GJs by 2025, our timely production escalation perfectly positions us to be a primary contender in Enbridge Gas's Procurement Process. This anticipated collaboration will not only diversify our client base and potentially boost our revenue streams, but also solidify our standing as a leading RNG producer in the region.

Generate Upcycle would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Brandon Moffatt
Vice President of Development, Generate Upcycle
Date: 2023-09-06
Signed: Brandon Moffatt

VIRIDI

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

September 8, 2023

Re: RNG Support Letter for Enbridge

To whom it may concern,

Viridi Energy LLC produces/has intention to produce RNG from diverse feedstocks at the production locations listed below. Viridi Energy has existing projects that will produce over 3.1million GJ of RNG by 2026, and is working on other opportunities that could expand RNG production to 8 million GJ/year over the same timeframe.

Type	Location	Volume GJ/year	COD
Biosolids	New England	185,000	2026
Dairy	Upper Midwest	225,000	Q2 2025
Food Waste	New York	530,000	2025
Landfill	Wisconsin	340,000	Q4 2024
Landfill	New England	475,000	Q3 2023
Landfill	Alabama	175,000	Q3 2025
Poultry	Midwest	315,000	Q3 2024
Poultry	Mid-Atlantic	685,000	2025
Swine	Southeast	55,000	Running
Swine	Southeast	140,000	Running

Viridi Energy believes that a healthy and diversified voluntary market for RNG is the key to transforming this industry from a niche transportation fuel alternative into a strategic and dependable renewable energy choice. Enbridge is an ideal counterparty for RNG producers. Financially, Enbridge can offer a solid credit-worthy offtake contract that enables developers to access credit markets to do more RNG projects. Operationally, Enbridge understands how gas moves from injection to end user. And Enbridge has a vested interest in the success of the RNG market.

Viridi Energy LLC would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Very Truly Yours,

William Keller

Bill Keller

Executive Vice President,
Marketing and Strategy
Viridi Energy LLC

From: Joshua Samuel <jsamuel@northeastmidstream.com>
Sent: Friday, September 8, 2023 1:29 PM
To: Nicole Brunner <Nicole.Brunner@enbridge.com>
Cc: Steve Rakidzioski <Steve.Rakidzioski@enbridge.com>
Subject: [External] Enbridge 2024 Rate Case (EB-2022-0200) - RNG Procurement

CAUTION! EXTERNAL SENDER
Were you expecting this email? TAKE A CLOSER LOOK. Is the sender legitimate?
DO NOT click links or open attachments unless you are 100% sure that the email is safe.

Hello Nicole.

Radius RNG LP is advancing a construction-stage portfolio of high-quality, on-farm renewable natural gas (RNG) facilities to reduce emissions from agricultural operations in southern Ontario and decarbonize the natural gas system for homes and businesses.

Renewable energy solutions are needed to help our province and our communities reach their net-zero emissions targets. By converting on-farm feedstocks into RNG, we're not only reducing emissions across the agricultural sector. We're helping communities move to a cleaner, more sustainable future by providing a carbon-negative renewable energy for space heating and domestic hot water within our homes and businesses and steam and process heat for industry.

Radius RNG LP expects to produce up to 1.8 million GJ per year of RNG from its cluster of RNG facilities in southern Ontario, with the first RNG facility available for commercial operation in 2025.

Enbridge's procurement of RNG would translate into tangible benefits for Ontario's natural gas customers. It would reduce greenhouse gas emissions, leading to cleaner air and a healthier environment. Moreover, RNG diversifies the energy mix, enhancing energy security and potentially stabilizing prices for consumers in the long run.

Radius RNG LP would be interested in participating in Enbridge's RNG procurement process if Enbridge were to receive a favorable decision from the Ontario Energy Board in the 2024 Rate Case.

Regards,

Joshua Samuel
President of the General Partner
Radius RNG LP

September 8, 2023

To whom it may concern:

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

This Rate Case is currently active in front of the OEB with an expected decision by the OEB potentially delivered in mid-2024 (the "**Decision**"). If approved on this schedule, Enbridge Gas will begin procuring RNG from the market, seeking first delivery in 2025. In alignment with Enbridge Gas' Gas Supply Planning Principles, Enbridge Gas would be seeking reliable, secure, and cost-effective supply from a diverse range of suppliers and with diverse contract terms. Enbridge Gas would run a competitive process (the "**Procurement Process**") to seek contracts for procurement of RNG to meet these targets upon a favourable Decision in 2024.

SusGlobal Energy Corp. ("**SusGlobal**") has intention to produce RNG from Source Separated Organics at its Eastern Ontario Belleville Organic Waste Processing Facility and its Western Ontario Hamilton Organic Waste Processing Facility. SusGlobal will produce approximately 675,000 GJ of RNG per year with plans to increase to 900,000 GJ per year by the year 2030.

Having two (2) RNG facilities in Ontario near the Enbridge Dawn Hub, the largest gas facility in North America, is an advantage for many reasons. Primarily, Enbridge will be able to purchase RNG without the need to transport the RNG by truck tanker as it will be connected to the existing Enbridge pipeline at our doorstep. Transporting RNG by pipeline reduces the carbon footprint of transportation which is a key driver of the Climate Change initiative. Secondarily, SusGlobal RNG producer relationship with Enbridge will contribute to the important role that RNG will play as part of a diversified energy future for the province.

- SusGlobal was chosen by The Finnish Innovation Fund Sitra ("**Sitra**"), as one of 39 inspiring circular economy solutions from around the globe during the World Circular Economy Forum, September 29-30, 2020. https://www.sitra.fi/en/projects/wcefonline/

- SusGlobal received a (**B-**) score with scorecard from Circulytics®, launched by The Ellen MacArthur Foundation ("**The Foundation**"), a charity whose mission is to accelerate the transition to a circular economy. https://ellenmacarthurfoundation.org/resources/circulytics/overview

- The SusGlobal Belleville Ontario Organic Waste Processing and Composting Facility is registered on the CSA GHG CleanProject® Registry and monetizes carbon credits. https://www.csaregistries.ca/GHG_VR_Listing/CleanProjectDetail?ProjectId=909

200 Davenport Road | Toronto, Ontario Canada | M5R 1J2
T 416.223.8500 | **TF** 866.512.SESG (7374) | **F** 416.223.8507 | **www.susglobalenergy.com**

- SusGlobal RNG facilities will produce approximately 36,000 dry tonnes per year of Digestate which will be processed and sold as SUSGRO® Organic Liquid Fertilizer an award-winning product, recipient of Lucintel's "2021 Product Innovation Award in the Fertilizer Market" which serves the $16 billion organic segment of the $200 billion global fertilizer market.

SusGlobal is aligned with this diversified initiative as LEADERS IN THE CIRCULAR ECONOMY.®

SusGlobal would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Yours truly,

SusGlobal Energy Corp.

Marc Hazout

Marc Hazout
Chairman and Chief Executive Officer

BRADAM energies

The Solution is Clear. The Future is Clean.

BRADAM Canada has the intention to produce renewable natural gas (“RNG”) from Organic Waste at two facilities being developed in Napanee and Hamilton, Ontario using our BRADAM CER™.

BRADAM Canada will produce:

1) Napanee - 1,800,000 GJ of renewable natural gas per year beginning in the fall of 2025 from the initial process line, with plans to increase to 3,600,000 GJ per year, with the addition of a second process line by the year 2027.

2) Hamilton - 1,800,000 GJ of renewable natural gas per year beginning in the winter of 2025 from the initial process line, with plans to increase to 3,600,000 GJ per year, with the addition of a second process line by the year 2027.

The BRADAM CER™ was originally developed in Sault Ste. Marie and the market conditions now exist to begin developing large scale RNG facilities in North America. BRADAM has several opportunities to export RNG throughout North America, from either facility, however transportation costs outside of the Province erode much of the investor margin, simply due to the location of the facility versus the current markets.

As a patented process developed in Ontario, with much of our engineering team and strategic partners located in Ontario, we prefer to begin our development roll out in Ontario. Having a regional off-take for our RNG at market value and absent of transportation costs associated with continental delivery of RNG will provide the investor confidence to develop multiple additional facilities in Ontario.

The BRADAM CER™ is a unique process which allows the processing of any organic waste including organics contaminated with plastics. The process is a closed loop and does not burn or incinerate any of the feedstock and provides a very high energy recovery from the feedstock. All material is processed into RNG, inert aggregate, and water, with no waste of any type leaving the facility. The gas produced is subject to a C14 test prior to leaving the facility to quantify the amount of RNG (from organics) versus SNG (from the trace plastics) exported. The BRADAM CER™ process also eliminates PFAS chemicals typically found in food organics which have inherent liability when they are disposed of in landfills or used to make compost, or in the case of digestors when the digestate is used for land applications of any type.

Ontario is moving forward with a ban on landfilling organics and in particular food waste. The challenge is simply there is no way to process all this contaminated food waste and remove the PFAS chemicals in digestors or composting. Hence the producers of the food waste, have no avenue to process their waste, and absolve themselves of any future liability surrounding PFAS chemicals.

The marketplace is demanding RNG in an effort to lower carbon emissions, however the capacity to produce RNG is minimal and with the low energy conversion rate of digestors coupled with the challenges of PFAS and plastics contamination in the digestate, investors are quickly moving away from supporting off farm digestors.

BRADAM can solve both of these issues in Ontario and the current market has enough organic waste to support approximately 20 BRADAM CER™ process lines with an annual production of 72,000,000 GJ per year. BRADAM can completely process this waste stream into a high yield RNG, eliminate the dangerous PFAS chemicals, produce water and an inert aggregate, and do so absent of any waste at the end of the process.

Having a local market for our RNG would increase investor confidence and expediate our ability to develop the Ontario marketplace.

BRADAM Canada would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Date: September 7, 2023

Bruce Garner
SVP Operations
519-532-2600
bruceg@bradamenergies.com

2-610Ford Drive, Suite 109, Oakville, Ontario L6J 7W4

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

To whom it may concern:

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

This Rate Case is currently active in front of the OEB with an expected decision by the OEB potentially delivered in mid-2024 (the "**Decision**"). If approved on this schedule, Enbridge Gas will begin procuring RNG from the market, seeking first delivery in 2025. In alignment with Enbridge Gas' Gas Supply Planning Principles, Enbridge Gas would be seeking reliable, secure, and cost-effective supply from a diverse range of suppliers and with diverse contract terms. Enbridge Gas would run a competitive process (the "**Procurement Process**") to seek contracts for procurement of RNG to meet these targets upon a favourable Decision in 2024.

Through this letter, Enbridge Gas is actively requesting information from you as a RNG producer as follows:

Evergreen Environmental Inc. produces/has intention to produce RNG from organic waste at 1515 Thornton Rd N, Oshawa. Evergreen Environmental Inc will produce at minimum 300,000 GJ of renewable natural gas per year with plans to increase to > 500,000 GJ by the year 2028

Enbridge purchasing RNG will allow Evergreen, with the only permitted merchant site in GTA to provide a 100% local Ontario solution and as a result would support a more attractive business case for Evergreen Oshawa facility as it would potentially reduce the costs a related to inter provincial transport. In addition it would have the additional benefit for Evergreen and Enbridge to showcase a solution well located as related to connecting to Enbridges high pressure infrastructure.

Evergreen Environmental Inc. would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Date: 2023- 09- 05

Signed:

Ward Janssens

Evergreen Environmental Inc

CEO/President

E: wjanssens@egreens.ca

T: (519) 500 8176

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

To whom it may concern:

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

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Through this letter, Enbridge Gas is actively requesting information from you as a RNG producer as follows:

Green Shields Energy produces/has intention to produce RNG from MSW, Biomass and Biosolids at Sarnia Ontario. Green Shields Energy produces 0 GJ of renewable natural gas per year with plans to increase to 6,000,000 GJ by the year 2025.

Section on how Enbridge purchasing RNG will benefit your company or any organizational impact statements you want to make (Write as much or as little as you would like)

Enbridge's pre purchase of RNG and or associated carbon credits will help my company secure financing to build and or expand our pipeline and project development. It will give us certainty that the market is stable, robust and growing. Enbridge also supports the diversion of waste from landfills further reducing GHG emissions.

Green Shields Energy would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Date: September 5, 2023

Signed:

CHAR technologies
ALTECH CHARTECH SOLUTIONS

ONTARIO ENERGY BOARD

September 7th, 2023

Re: Enbridge 2024 Rate Case (EB-2022-0200) for approval of a low-carbon energy procurement

To Whom it May Concern,

CHAR Technologies Ltd (CHAR) produces renewable natural gas (RNG) and biocoal from the conversion of wood waste through high temperature pyrolysis (HTP) at our Thorold, Ontario facility. The Thorold facility was jointly funded with over $14M by the Governments of Ontario and Canada to scale-up production in 2024, increasing the facilities capacity to 500,000 GJ of RNG/yr and 10,000 tonnes of biocoal/yr from the HTP conversion of 75,000 tonnes/yr of wood wastes.

CHAR is a strategic partner of a world leading steel and mining company, ArcelorMittal S.A. (ArcelorMittal) that is the parent company to Ontario's largest steel producer, ArcelorMittal Dofasco (AMD) in Hamilton, Ontario. AMD has already signed an MOU to purchase and consume CHAR's biocoal to support the decarbonization of their Electric Arc Furnace (EAF) green steel transition by 2028.

In the next five years, CHAR intends to have in production 3,000,000 GJ/yr of renewable natural gas and, simultaneously, 60,000 tonnes/yr of biocoal. The produced biocoal will be sufficient volume to completely replace AMD coal usage in their new EAF green steel production. This will be entirely made possible by the revenues to be generated by RNG sales to large utilities, ideally in Ontario, but in other jurisdictions if required.

Enbridge has been a pivotal ally in CHAR's project development process. Although not currently a significant participant in the RNG purchasing market, Enbridge has aided CHAR by consulting, on a good faith basis, on how to best bring the RNG to market.

An example of Enbridge's support has been demonstrated through their front-end engineering and design consultations for CHAR's Lake Nipigon project. The Lake Nipigon project is a partnership between CHAR and the Indigenous communities of Animbiigoo Zaagi igan Anishinaabek (AZA), Bingwi Neyaashi Anishinaabek (BNA), Biinjitiwaabik Zaaging Anishinaabek (BZA), and the Red Rock Indian Band.

CHAR would be interested in participation in Enbridge's Procurement Process if they were to receive a favourable decision in the Rate Case, and CHAR strongly supports Enbridge's Rate Case Application with the Ontario Energy Board.

Sincerely,

Andrew White
CEO
CHAR Technologies Ltd.
(647) 968-5347
andrew.white@chartechnologies.com

ENBRIDGE

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

To whom it may concern:

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

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Through this letter, Enbridge Gas is actively requesting information from you as a RNG producer as follows:

Amp Americas ("Amp") produces RNG from animal waste at multiple facilities in North America. In 2022, Amp produced approximately 1.4 PJ of renewable natural gas and will increase its production by at least another 1 PJ in the next 24 months.

Amp is a developer that builds, owns, and operates RNG facilities, producing 100% renewable, carbon negative fuels and feedstocks from animal waste at farms. The production of RNG, especially animal waste RNG, is a key decarbonization solution which prevents methane emissions and is a drop-in replacement for fossil natural gas. Programs and incentives for RNG to be used in North America reduce methane emissions, decrease fossil fuel demand, and support growth in the RNG industry.

Amp would be interested in participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Date: 9/6/2023

Sincerely,

Andy Dvoracek

VP, Business Development

TORONTO

Matt Keliher
General Manager

Will Johnston
Deputy City Manager

Solid Waste Management Services
City Hall
100 Queen Street West
25th Floor, East Tower
Toronto, ON M5H 2N2

Tel: 416-392-4715
Fax: 416-392-4754
Matt.Keliher@toronto.ca

September 6, 2023

To Whom It May Concern,

Re: Enbridge Gas 2024 Rate Case (EB-2022-0200)

The City of Toronto understands that Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of it's 2024 Rate Case for approval of a low-carbon energy procurement which, if approved, would enable Enbridge Gas to procure up to 1% of its forecasted gas supply purchases in 2025 as low carbon energy – primarily in the form of renewable natural gas (RNG).

The City of Toronto produces RNG from biogas at it's Dufferin Organics Processing Facility, with plans to begin producing RNG from biogas at the Disco Road Organics Processing Facility in early 2024, and from landfill gas at the Green Lane Landfill in 2026. The City of Toronto produces 48,000 GJ of renewable natural gas per year with plans to increase production to 1,267,000 GJ by the year 2027. Currently, the RNG produced at the Dufferin and Disco Organics Processing Facilities has been directed by City Council to be self-consumed by City infrastructure.

However, with RNG production expected to increase by over 24x in the next 4 years as the City implements a landfill gas-to-RNG project with no presently defined end use, allowing Enbridge to purchase RNG could provide significant support to the City's RNG production plans. Having the option to sell the RNG the City produces to Enbridge would help the City offset the costs of its RNG projects, improving the financial sustainability of the City's long-term RNG Strategy. In turn, this would bolster the business case for additional RNG production projects moving forward. Ultimately, as a reliable, low-risk, and low-transaction cost purchasing partner, Enbridge having the ability to purchase RNG would directly support the sustainability of the RNG projects underway at the City and the expansion of existing installations moving forward.

The City of Toronto would consider participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Yours truly,

Matt Keliher
General Manager
Solid Waste Management Services

MK/sf

3 1 1
toronto at your service

ENBRIDGE

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

To whom it may concern:

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

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Through this letter, Enbridge Gas is actively requesting information from you as a RNG producer as follows:

Greenfield Global Inc. ("Greenfield") is leading the development of a renewable natural gas ("RNG") production facility in Chatham-Kent, Ontario. The Chatham-Kent "Waste-to-Energy" Project will be a partnership between Greenfield, the Municipality of Chatham-Kent, and the Chatham-Kent PUC.

The Waste-to-Energy Project will be a shining example of Ontario's circular economy in action. The state-of-the-art facility will utilize anaerobic digestion technology (AD) for processing approximately 90,000 to 120,000 tonnes annually, including municipal and industrial, commercial & institutional (ICI) organic waste, organic waste streams from Greenfield's adjacent ethanol plant and wastewater sludges from the Chatham-Kent PUC Wastewater Treatment Plant.

In turn, the AD process will produce digestate and biogas. Digestate will be dewatered and dried to produce a fertilizer for agricultural use. Biogas will be upgraded to renewable natural gas (RNG) for direct injection into Enbridge's pipeline. The projected RNG production is approximately 500,000 GJ per year by mid 2026.

Ideally, Greenfield will sell the RNG, through Enbridge, into the Ontario market to support Ontario businesses – industrial, commercial, and agricultural - as they strive to remain competitive, reduce carbon emissions and enhance their long-term operational sustainability. Greenfield strongly believes that Enbridge's ability to purchase RNG is an essential condition to the development of strong RNG market in Ontario, similar to markets in British Columbia and Quebec where utilities directly purchase RNG. In the absence of this type of developing market, Greenfield will in all likelihood sell its RNG to utilities/parties outside of Ontario. As a result,

Ontario businesses will not have the benefit of Ontario produced RNG, and the circular economy value will be broken.

*Greenfield Global Inc. is interested in participating in Enbridge's Procurement **Process** if Enbridge were to receive a favorable Decision in the Rate Case.*

Date: September 6, 2023

Signed:

Tom Teahen, SVP Advanced Fuels
Greenfield Global Inc.

RURAL GREEN ENERGY INC.

To Whom it May Concern

REFERENCE: Ontario Energy Board (OEB) 2024 Rate Case (EB-2022-0200)

CNG/RNG Rural Green Energy Inc (RGE) through its affiliated company is a current private RNG producer in Ontario. This gas is produced through the decomposition of manure and community organics. This facility is currently an M13 contracted producer, in Illderton Ontario, suppling consumers outside of Ontario.

RGE intends to bring 200,000 – 1 million GJs of new production online each year starting 2025 each year between 2025 and 2030. Allowing Enbridge to procure some portion of this gas in a clear, stable, and transparent regulated environment will allow RGE to provide Ontarians with the locally produced, cost effective energy that they require for their homes and businesses.

Approval of this this rate case will allow RGE to grow our Ontario Operations and provide local low carbon economy jobs, and help with Ontario's energy transition. Leveraging the assets in the Dawn Natural Gas Storage infrastructure we will bring low carbon, **dispatchable** energy to Ontario's consumers and business.

Regards,
CNG/RNG Rural Green Energy Inc.

Nicholas Hendry, CD, rmc, MSc (Eng), P.Eng.

President

440 Wright Blvd. Unit #2,
Stratford, ON. N4Z 1H3

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

To whom it may concern:

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

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Through this letter, Enbridge Gas is actively requesting information from you as a RNG producer as follows:

The City of Guelph has intention to produce RNG from wastewater treatment and organic waste processing at our Water Resource Recovery Centre and Waste Resource Innovation Centre.

Enbridge purchasing RNG will benefit the City of Guelph by improving the financial viability of RNG production projects at our facilities. These projects are key steps towards Guelph's Race to Zero targets to be a net zero carbon community by 2050 or earlier.

The City of Guelph would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Date: September 6, 2023

Signed:

Bryan Ho-Yan, M.A.Sc., P.Eng., CEM

Manager, Corporate Energy and Climate Change

City of Guelph

519-822-1260 extension 2672

bryan.ho-yan@guelph.ca

ENBRIDGE

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

To whom it may concern:

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

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Through this letter, Enbridge Gas is actively requesting information from you as a RNG producer as follows:

Matter Global Solutions Inc., produces/has intention to produce RNG from agricultural wastes primarily, corn stover, straw and animal manures at the Ridgetown, Ontario site. A partnership with the University of Guelph. This project is a designed to upgrade the current facility and provide a commercial showcase for future projects. Matter will produce upwards of 250,000 GJ of renewable natural gas per year with plans to increase to 1,000,000 GJ by the year 2026. Matter is actively developing projects in Ontario with a focus on residue straw/stover feedstock supply, utilizing a new generation of anaerobic digestion ("AD") and pre-treatment technology. This approach will provide a solution for the underutilized agricultural market and act as a catalyst for commercial organic soil enhancements and carbon sequestration creating vibrant Ontario farmlands.

The proposed Enbridge purchasing strategy for RNG would provide meaningful benefits to the growing AD market and specifically help Matter to accomplish its large-scale business objectives for partnering with Ontario farmers to supply clean energy, significantly reduce greenhouse gases and provide a much-needed program for enhancing farmland and soil biology. The Enbridge proposal will directly provide investment opportunities in Ontario with long-term contracts and competitive pricing to secure project financing and create new employment and construction opportunities. Ontario could become a leader in new clean energy and technology development by supporting this timely and much needed proposal from Enbridge.

Matter would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Date: September 6,2023

Signed:

Jay Zwierschke, President – Matter Global Solutions Inc.

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

To whom it may concern:

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

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Through this letter, Enbridge Gas is actively requesting information from you as a RNG producer as follows:

Convertus Group ("Convertus") is the largest, most advanced organic waste processor in Canada. We currently operate 12 sites across Canada and 1 site in the US. Notably, our sites include two large organic waste processing facilities in Ontario. In addition, Convertus was recently awarded a 20-year contract with York Region to process up 140,000 tonnes of source-separated organic ("SSO") waste annually. As part of this contract, Convertus will design, build, finance, and operate an anerobic digestion facility with annual permitted capacity of 200,000 tonnes to support additional municipal green bin programs and the industrial, commercial, and institutional sectors. This project will be the Largest Biofuel Facility in Canada and will support York Region by processing the entirety of its organic waste as well as surrounding Greater Toronto Area ("GTA") municipalities starting in Q1 of 2027.

Our Biofuel Facility is critically important organic waste processing infrastructure that offers a responsible, long-term waste management solution for York Region and its residents. By constructing this facility in-region we will reduce greenhouse gas emissions by 15,000 metric tonnes annually from York Region having shortened haul distances as waste is currently transported 160km to 400km out of region for processing. In addition, Convertus will produce up to 400,000 GJ of renewable natural gas ("RNG") per year at the Convertus Biofuel Facility subsequently reducing C02 emissions by 12,000 tonnes annually.

Securing an RNG offtake contract with Enbridge would allow Convertus to directly inject our RNG produced from anaerobic digestion of organic waste into Enbridge's existing natural gas pipeline located near the facility to be utilized as a renewable energy source within the Province of Ontario.

Allowing RNG producers to directly contract with Enbridge to purchase and distribute renewable natural gas in the province enables further reduction of greenhouse gas emissions otherwise generated from transporting the gas molecules out of province to other utility purchasers and voluntary markets, while subsequently contributing to Ontario's Climate Change Strategy to target 30 percent reduction in greenhouse gases by 2023 from 2005 levels in support of the Federal framework implemented to meet net zero by 2050.

Currently, other provinces and states such as British Columbia, Quebec, and California have created ecosystems for renewable energy production and selling through established utilities that purchase RNG such as Energir and FortisBC. These programs enable and support local production, purchase, and distribution of the RNG within the utility's own province. We believe Enbridge is working ardently to create the same opportunity in Ontario to help meet provincial and federal carbon reduction targets.

Convertus invests in carbon reduction innovation and technology and would prefer to support carbon reduction mandates of the province we operate in. This also allows for further investment in green infrastructure that implements technical solutions to reduce C02 emissions. To help fight climate change RNG producers in Ontario require significantly important policy support and existing networks and programs such as Enbridge's proposed RNG program to effectively contribute to overall emission reduction targets.

We strongly encourage and support Enbridge's initiative to support the growth and strength of renewable natural gas production in Ontario by providing the existing pipeline infrastructure and program capabilities for RNG producers to sell gas to an established utility for provincial use.

Convertus would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case or request Enbridge participate in Convertus' upcoming RFP procurement process.

Date: September 12, 2023

Signed:

Annie Ironmonger

Director of Business Development

Convertus Group

ENBRIDGE

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

To whom it may concern:

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

This Rate Case is currently active in front of the OEB with an expected decision by the OEB potentially delivered in mid-2024 (the "**Decision**"). If approved on this schedule, Enbridge Gas will begin procuring RNG from the market, seeking first delivery in 2025. In alignment with Enbridge Gas' Gas Supply Planning Principles, Enbridge Gas would be seeking reliable, secure, and cost-effective supply from a diverse range of suppliers and with diverse contract terms. Enbridge Gas would run a competitive process (the "**Procurement Process**") to seek contracts for procurement of RNG to meet these targets upon a favourable Decision in 2024.

Through this letter, Enbridge Gas is actively requesting information from you as a RNG producer as follows:

Ridgeline Farm produces/has intention to produce RNG from (anaerobic digestion of agri-food feedstock at their farm in Stirling, Ontario. Ridgeline Farm will produce produces 63,000 GJ of renewable natural gas per year with plans to increase to 107,000 GJ by the year 2025.

Purchasing RNG will benefit our farm in so many ways. Namely it will help our family diversify our farm's income and help contribute to the farm's future financial sustainability, and as important, it will allow us to contribute to the fight against climate change which is one of our family's guiding principles.

Ridgeline Farm would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Date: September 26th, 2023

Signed: ______________________

Mark Donnan – Owner

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

To whom it may concern:

Enbridge Gas has applied to the Ontario Energy Board (OEB) as part of its 2024 Rate Case (EB-2022-0200) (the "**Rate Case**") for approval of a low-carbon energy procurement (Section 4.2.7) which, if approved, would enable Enbridge Gas to procure up to 1% of its forecast gas supply purchases (approximately 5.3 PJ/year) in 2025 as low carbon energy - primarily in the form of renewable natural gas ("**RNG**") (as defined n the *Greenhouse Gas Pollution Pricing Act*). The low carbon energy procurement part of the Rate Case also requests an increase to Enbridge Gas' 2025 low carbon energy purchases by 4% (approximately 21 PJ/year) per year of its forecast supply purchases by 2028.

This Rate Case is currently active in front of the OEB with an expected decision by the OEB potentially delivered in mid-2024 (the "**Decision**"). If approved on this schedule, Enbridge Gas will begin procuring RNG from the market, seeking first delivery in 2025. In alignment with Enbridge Gas' Gas Supply Planning Principles, Enbridge Gas would be seeking reliable, secure, and cost-effective supply from a diverse range of suppliers and with diverse contract terms. Enbridge Gas would run a competitive process (the "**Procurement Process**") to seek contracts for procurement of RNG to meet these targets upon a favourable Decision in 2024.

Through this letter, Enbridge Gas is actively requesting information from you as a RNG producer as follows:

The Corp. of the City of Timmins produces/has intention to produce RNG from Co-Digested Source Separated Organics using anaerobic digestion at the Mattagami Water Pollution Control Plant. The Corp. of the City of Timmins forecasts to produce between 22,960 GJ/year to 30,070 GJ/year as identified in City's feasibility study.

The Source Separated Organics Co-digestion and Energy Generation project supports plans for the city to reduce food and organic waste going to landfill, which frees up limited capacity in the landfill and reduces GHG emissions from methane generation from the breakdown of organics in the landfill.

The City of Timmins would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Date: September 15, 2023

Signed:

Scott Tam

Scott Tam, C.E.T., EP
Director of Growth & Infrastructure, City of Timmins

SKYLINE
CLEAN ENERGY FUND

September 28, 2023

To whom it may concern,

SkyMar Biogas Holdings LP (SkyMar) produces, and has the intention to continue producing, a significant quantity of quality Renewable Natural Gas (RNG) from the anaerobic digestion of organic materials sourced from across Canada, with current and projected facilities in Ontario, Alberta, and British Columbia. SkyMar currently has the ability to produce 400,000 GJ of RNG per year with plans to increase to over 2 million GJ per year by 2030. SkyMar currently owns and operates two anaerobic digestion facilities in Elmira, Ontario, and Lethbridge, Alberta. The Lethbridge Facility is currently producing RNG while the Elmira Facility is in the process of doubling its capacity and converting to RNG with an expected commencement date in 2025. When commissioned, the facilities will have a combined RNG production capacity of 850,000 GJ per year.

Skyline Clean Energy Fund (SCEF), the primary shareholder of SkyMar, is a Canadian clean energy solutions provider and one of Canada's largest producers of biogas. Collectively, we are part of $8.2+ billion Skyline Group of Companies (Skyline) which owns, manages, develops, and offers investments in both real estate and clean energy. Through our $293+MM investment (and growing) in clean energy assets and infrastructure, we support the group of companies' overarching sustainability commitments in alignment with UN SDG 7 (affordable and clean energy).

We are playing a role in accelerating Canada's transition to clean energy by making strategic long-term investments in energy solutions that promote a circular economy. We have identified several opportunities for further optimization/expansion of our existing biogas facilities, and we are continuing to seek opportunities for further facility acquisition. RNG provides a cleaner alternative to fossil fuels and we believe that it is a viable bridge fuel as Canada builds the infrastructure required to fully transition to renewable energy. We will continue to seek opportunities to invest in it for our needs as a group of companies.

Enbridge's procurement of RNG would enhance our ability to supply quality RNG to the markets where Skyline operates, in a manner that would enable diversified use of clean fuels. For example, locally created RNG could be a fuel option for properties that Skyline owns—an initiative that is in direct alignment with Skyline's vision to build strong, supportive, and sustainable communities.

SkyMar would be interested in potentially participating in Enbridge's Procurement Process if they were to receive a favorable Decision in the Rate Case.

Rob Stein
President, Skyline Clean Energy

STORAGE SPACE REGULATION

JASON GILLETT, DIRECTOR S&T BUSINESS DEVELOPMENT
MATT THOMAS, MANAGER S&T BUSINESS DEVELOPMENT

1. Enbridge Gas has provided this evidence to reflect the following issue that is being addressed in Phase 2 of this Application.

   47) Should the cap on cost-based storage service for in-franchise customers established in the NGEIR decision remain at 199.4 PJ?

2. The purpose of this evidence is to support maintaining the 199.4 PJ[1] of utility (cost-based) storage space service for in-franchise customers established in the Natural Gas Electricity Interface Review (NGEIR) Decision[2].

3. The NGEIR Decision in 2006 established the amount of storage space EGD and Union were required to reserve at cost-based rates for in-franchise customers. EGD was directed to continue to provide its 99.4 PJ of existing storage space for in-franchise customers. In addition to the existing cost-based storage space, EGD purchased 21.3 PJ of market-based storage space in the competitive market. Union was directed to reserve 100 PJ of its storage space for in-franchise customers. At the time of NGEIR, Union owned and operated approximately 160 PJ[3] of storage space. The OEB directed that storage space owned by Union in excess of the 100 PJ be permanently allocated as a non-utility asset which Union could continue to sell at market-based rates (i.e., not rate-regulated by the OEB). The shareholder assumed the risk associated with the non-utility storage space. Union did not

[1] Does not include 0.3 PJ of utility space in the Crowland pool.
[2] EB-2005-0551, Decision and Order.
[3] Does not include 4.4 PJ of affiliate storage at the time of NGEIR.

require the full 100 PJ of cost-based storage space to serve in-franchise customers at the time of NGEIR.

4. On a combined basis, the cost-based storage space available to provide service to Enbridge Gas in-franchise customers is the total of the EGD and Union amounts reserved for in-franchise customers of 99.4 PJ and 100 PJ, respectively, or 199.4 PJ in total for Enbridge Gas.

5. This evidence is organized as follows:
    1. Summary of NGEIR Proceeding & Decisions
    2. Benefits and Outcomes of the NGEIR Decision
    3. Changes Since Amalgamation
    4. Summary

1. Summary of NGEIR Proceeding & Decisions

1.1. Natural Gas Storage Regulation

6. The NGEIR proceeding was initiated by the OEB in late 2005 in response to issues first raised in the OEB's Natural Gas Forum Report[4] and more fully explored in the OEB staff report, Natural Gas Electricity Interface Review.[5] The key issues addressed in that proceeding were rates and services for gas-fired generators and storage regulation.

7. In the NGEIR Decision, the OEB outlined its objectives which included:
    a) To facilitate competition in the sale of gas to users;

[4] Natural Gas Regulation in Ontario: A renewed Policy Framework, Report on the Ontario Energy Board Natural Gas Forum, March 30, 2005, https://www.oeb.ca/documents/consultation_ontariogasmarket_report_300305.pdf .
[5] EB-2005-0306, Natural Gas Electricity Interface Review, A Report by Ontario Energy Board Staff, November 21, 2005, https://www.oeb.ca/documents/cases/EB-2005-0306/ngf_geinterface_report-211105.pdf .

b) To protect the interests of consumers with respect to prices and the reliability and quality of gas service; and

c) To facilitate rational development and safe operation of gas storage. [6]

8. At the time of NGEIR, EGD and Union operated underground gas storage facilities in Southwestern Ontario. Those facilities, which are connected to multiple gas transmission pipelines, are part of what is known as the Dawn Hub, one of the most important natural gas market centres in North America and the most important natural gas market centre in Ontario.

1.2. Determination of Space

EGD Rate Zone

9. At the time of NGEIR, the EGD rate zone required 120.7 PJ of storage space to meet the needs of in-franchise customers. This was 21.3 PJ greater than the 99.4 PJ of storage space of the EGD storage facilities. Therefore, the entirety of the EGD storage space (99.4 PJ) was required to serve its in-franchise customers while the remaining 21.3 PJ of space was procured from the competitive market.

10. In its NGEIR Decision, the OEB determined that EGD in-franchise customers would continue to receive service at cost-based rates for all 99.4 PJ of EGD storage space. Additional storage space requirements above the 99.4 PJ would continue to be procured from the competitive market.

Union Rate Zones

11. At the time of NGEIR, Union rate zone customers required approximately 92 PJ of storage space. This was significantly less than the 160 PJ of total storage space of

[6] EB-2005-0551, Decision with Reasons, November 7, 2006, pp.43-44.

the Union storage facilities. The OEB "decided that Union will reserve approximately two-thirds of its existing capacity for in-franchise needs."[7]

12. In its Decision, the OEB determined that Union would reserve 100 PJ of storage space to serve its in-franchise customers at cost-based rates. The OEB explicitly acknowledged that Union would eventually use the entirety of this allocation and stated:

> The Board acknowledges that there is no single, completely objective way to decide how much should be reserved for future in-franchise needs. The Board has determined that Union should be required to reserve 100 PJ (approximately 95 Bcf) of space at cost-based rates for in-franchise customers. This compares with Union's estimate of 2007 in-franchise needs of 92 PJ (87 Bcf). At an annual growth rate of 0.5% each year, which Union claims is the growth rate since 2000, in-franchise needs would not reach 100 PJ until 2024. The limit would be reached in 2016 if the annual growth is 1%; at a very annual high growth rate of 2% per annum, the 100 PJ limit would be reached in 2012.[8]

13. As a result of this Decision, Union reserved 100 PJ of cost-based storage space to provide service to in-franchise customers. Under current OEB-approved methodologies for determining the amount of storage required for in-franchise customers, the actual utilization is still below 100 PJ and is forecasted to be fully utilized by Union rate zone customers by the end of this decade.

14. The remaining 60 PJ of space was allocated to the non-utility storage operations. Since 1989, and prior to NGEIR, Union sold negotiated, market-based storage services to market participants both inside and outside of Ontario under the C1 rate schedule. The rate schedule included a minimum and maximum rate to be

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[7] EB-2005-0551, Decision with Reasons, November 7, 2006, p.4.
[8] Ibid, p.83.

negotiated for storage sales over peak and non-peak timeframes. Following NGEIR, Union continued offering the remaining 60 PJ as non-utility storage services at market-based rates in accordance with the NGEIR Decision.

1.3. Forbearance

15. In the NGEIR Decision, the OEB concluded "that it will refrain, in part, from regulating storage rates under section 36"[9] of the OEB Act. "Under forbearance, the utility shareholders would be expected to bear the risk of any storage development for the competitive market."[10] In addition, utility shareholders would bear the risk for revenues on the existing non-utility assets.

16. In the NGEIR Decision, the OEB concluded "that its determination that the storage market is competitive requires it to clearly delineate the portion of Union's storage business that will be exempt from rate regulation."[11]

17. This delineation was considered a permanent decision and as discussed further below, the OEB confirmed in the NGEIR Motion Decision that "the purpose of the 100 PJ cap is to establish a permanent allocation between utility and non-utility storage"[12] (emphasis added).

18. Further, in the NGEIR Decision the OEB stated that maintaining a perpetual call on Union's current capacity is not consistent with forbearance:

> Retaining a perpetual call on all of Union's current capacity for future in-franchise needs is not consistent with forbearance. As evidenced by the arguments from GMi and Nexen, two major participants in the ex-

[9] EB-2005-0551, Decision with Reasons, November 7, 2006, p.74.
[10] Ibid, p.51.
[11] Ibid, p.82.
[12] EB-2006-0322/EB-2006-0340, Decision with Reasons, July 30, 2007, p.7.

> franchise market, retaining such a call is likely to create uncertainty in the ex-franchise market that is not conducive to the continued growth and development of Dawn as a major market centre.[13]

1.4. Motion, Appeal and Decision

19. On November 7, 2006, the OEB issued its Decision with Reasons on the NGEIR proceeding.[14] In December 2006, the OEB received three Notices of Motion to review and vary the NGEIR Decision, including:
    - The decision to cap the amount of storage available at cost-based rates for in-franchise customers of Union at 100 PJ.

20. The OEB initiated a review of this issue and addressed three questions related to the NGEIR Decision that were raised in the motion review:
    a) If the cap of 100 PJ of storage for in-franchise Union customers remain[s] in place in perpetuity, what is the basis for forbearance (under section 29) of required storage above 100 PJ for in-franchise customers?
    b) If the cap of 100 PJ of storage for in-franchise Union customers does not remain in place in perpetuity, what mechanism should the OEB use to monitor the likelihood of the cap being exceeded?
    c) If the cap of 100 PJ of storage for in-franchise Union customers is likely to be exceeded, what, if any, remedy is available to in-franchise customers?[15]

21. On July 30, 2007, the OEB upheld the NGEIR Decision.[16]

[13] EB-2005-0551, Decision with Reasons, November 7, 2006, p.82.
[14] EB-2005-0551, Decision with Reasons, November 7, 2006.
[15] EB-2006-0322/EB-2006-0340, Decision with Reasons, July 30, 2007, p.4.
[16] EB-2006-0322/EB-2006-0340, Decision with Reasons, July 30, 2007.

22. In the NGEIR Motion Decision, the OEB reaffirmed that Union's in-franchise customers did not have an entitlement to the entirety of Union's storage assets and that the 100 PJ cap on storage space was appropriate, stating:

> The moving parties have in effect argued that Union's in-franchise customers should have a perpetual call on cost-based storage services from Union's storage assets because they are "utility" assets. The Board disagrees. In-franchise customers have no inherent entitlement to the entirety of the storage assets purchased, developed, and owned by Union. As the NGEIR Decision makes clear, Union's storage capacity was not developed exclusively for its in-franchise customer needs; a significant proportion was developed for the ex-franchise market.[17]

23. The moving parties suggested that the OEB should revisit this allocation in the future should the entirety of the 100 PJ of storage space be used to serve in-franchise customers. The OEB disagreed stating:

> This implies that there should be a re-examination of the allocation between "utility" and "non-utility" storage. The Board cannot foresee how such a re-examination would be justified. The re-allocation of "non-utility" storage to "utility" storage implies that the in-franchise customers have some sort of entitlement to the assets purchased, developed and owned by Union. As set out above, the Board finds that there is no basis for any such entitlement.[18]

24. The OEB was clear in the NGEIR Motion Decision that "the purpose of the 100 PJ cap is to establish a <u>permanent</u> allocation between utility and non-utility storage" [19] (emphasis added).

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[17] EB-2006-0322/EB-2006-0340, Decision with Reasons, July 30, 2007, p.6.
[18] Ibid, p.8.
[19] Ibid, p.7.

25. The implication of the NGEIR Decision and the NGEIR Motion Decision is that the amount of cost-based storage space available for Enbridge Gas customers has been fixed on a permanent basis. This determination was made after an 11-month generic proceeding convened by the OEB involving 40 parties, which was followed by fully contested and comprehensive review motions and an unsuccessful petition to the Lieutenant Governor in Council for review.

26. The fact that the OEB indicated that this determination is "permanent" must have meaning. This is a deliberate departure from most OEB (and administrative tribunal) determinations which recognize that one decision maker does not fetter the discretion of subsequent decision makers. Here, the OEB made a decision that they expected parties to rely upon going forward, including the separation of storage space between utility and non-utility in contracting with third parties and in developing new storage. Changing this determination now severely undercuts all the effort to create predictable market conditions for the natural gas market, including gas generation customers in Ontario that were at the root of the NGEIR process.

27. While this will become a matter for legal argument, Enbridge Gas does wish to highlight its view now (rather than waiting for final argument) that any move to rewrite the "permanent allocation" from the NGEIR proceedings is not appropriate. There is no reason to conclude that the decision at issue (permanent allocation of cost-based storage) was "wrong" at the time that it was made, which is the reason why administrative tribunals typically depart from prior determinations.[20] Moreover, while "*stare decisis*" (precedent) does not bind an administrative tribunal, the same

[20] *Canada (Attorney General) v Bri-Chem Supply Ltd* 2016 FCA 257.

cannot be said for equitable doctrines such as *res judicata*.[21] In this circumstance, the attempt to re-litigate the "permanent" allocation of cost-based storage should be disallowed based on *issue estoppel* (a type of *res judicata* claim).[22] Essentially, this is a circumstance where the same question is being raised a second time, in front of the same adjudicator, with substantially the same parties. It is not fair and just for the matter to be reheard, particularly in the face of the prior "permanent" decision.

<u>2. Benefits and Outcomes of the NGEIR Decision</u>

28. In the NGEIR Decision, the OEB determined that storage space in excess of the 100 PJ will be permanently considered a non-utility asset and in-franchise customers have no inherent entitlement to the storage space that had been developed by the utilities. This non-utility storage space continues to be contracted to storage customers on a long-term basis as a critical part of a robust and liquid market both inside and outside of Ontario. The OEB determined:

> That storage space in excess of the amount made available at cost-based rates (which is to be capped at 100 PJ – see Chapter 6) can be considered a "non-utility" asset. This is the space that will support Union's long-term storage sales. The Board finds that profits from new long-term transactions should accrue entirely to Union, not to ratepayers.[23]

<u>2.1 Development of Storage Market Since NGEIR</u>

29. As discussed above, two objectives of the NGEIR Decision were to facilitate rational development and safe operation of gas storage and to facilitate competition in the sale of gas to users.

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[21] *Penner v Niagara Regional Police Services Board* 2013 SCC 19 at para 31.
[22] Danyluk v Ainsworth Technologies, 2001 SCC 44.
[23] EB-2005-0551, Decision with Reasons, November 7, 2006, p.104.

30. In the NGEIR Decision, the OEB accepted that storage development is more akin to exploration and development and is riskier than other distribution activities. The OEB concluded that it was appropriate to facilitate the development of storage space without undue risk for ratepayers stating:

> The Board therefore agrees with Energy Probe's view, namely that the risks associated with new storage development are best borne by storage developers. This approach is consistent with a rational development of storage in the Board's view. Under forbearance, the utility shareholders would be expected to bear the risk of any storage development for the competitive market. [24]

31. Increased economic development in Ontario prompted the development of various products and services including High Deliverability Services for the power generation market. This non-utility storage has become integral to an active market that has matured since 2007 and includes customers and utilities beyond Ontario. The availability of market-based storage at Dawn has supported the development of the liquidity of the Dawn Hub, attracting pipelines and counterparties that offer commodity and natural gas services to Enbridge Gas as well as direct purchase customers in Ontario. As this market has developed, the number of counterparties that transact for storage services at Dawn has increased from 29 in 2010 to 55 in 2023, an increase of approximately 90%.

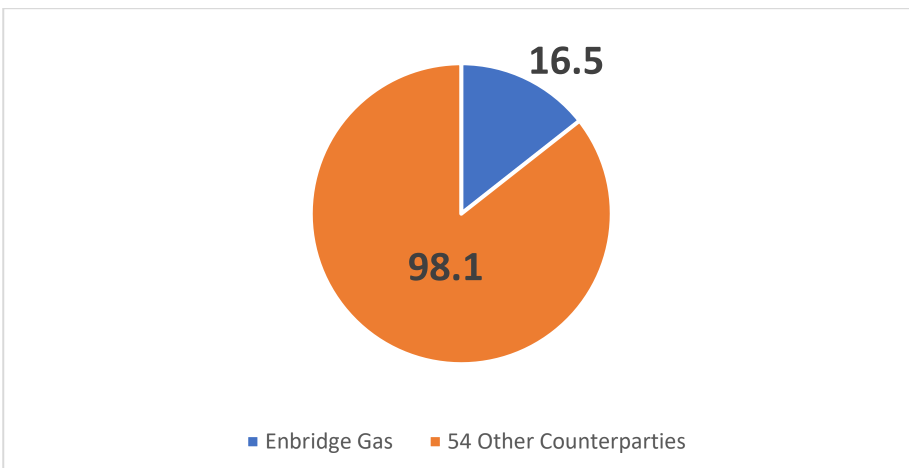
32. Since NGEIR, the EGD non-utility business has completed several capital investments to increase storage space and deliverability. These projects have increased storage space by 27.9 PJ and increased the withdrawal capability by 0.7 PJ/d. Additionally, the Union non-utility business has completed several capital

[24] EB-2005-0551, Decision with Reasons, November 7, 2006, p.51.

investments to increase storage space and withdrawal capability. These projects have increased storage space by 26.7 PJ and increased withdrawal capability by 1.0 PJ/d.[25]

33. There is a significant market that has been built upon the NGEIR Decision and the allocation of non-utility storage. As of April 1, 2024, Enbridge Gas has contracted non-utility storage services with 55 counterparties. Of the 114.6 PJ of non-utility physical space, 16.5 PJ is contracted to Enbridge Gas (approximately 14% of the total non-utility storage), while approximately 98.1 PJ is contracted to 54 other counterparties both within and outside Ontario.

Figure 1: Contracted Non-Utility Physical Space as of April 1, 2024 (PJ)



34. Investment and growth of storage at the Dawn Hub through non-utility storage has increased the overall depth and liquidity of the market at Dawn and provides value to all Ontario natural gas customers by way of competitive commodity pricing and attracting natural gas supply to the province. The unique position of Dawn in the North American energy landscape is supported by the combination of both pipelines

[25] The increases in storage space referenced in this paragraph also include items such as storage inventory adjustments and changes in heat value.

and non-utility storage services that market participants value. Since 2007, a number of pipeline expansions both upstream and downstream of Dawn have increased the liquidity of the Dawn market, including the Dawn Parkway System, TransCanada Mainline, and the construction of the NEXUS and Rover pipelines. The total design-day send out from Dawn has increased from approximately 6.7 PJ/d in 2007 to approximately 8.7 PJ/d in 2023, which is a 30% increase since NGEIR. Likewise, the volume exported from Parkway to customers east of the Dawn Parkway System has increased from approximately 1.1 PJ/d in 2007 to approximately 4.4 PJ/d in 2023, or a 300% increase. This dramatic growth is related to the increase of natural gas supply pipelines to Dawn, the availability of storage services at Dawn and the value customers place on those storage and transportation services.

35. This market has developed based on the currently available market-based storage and a change to that availability could disrupt the market by introducing uncertainty at Dawn, and in the Ontario market, that does not exist today. Reducing storage available in the market could have negative impacts for Ontario including direct purchase customers and other utilities, both inside and outside of Ontario, that depend upon a liquid Dawn market. Market participants have relied upon the predictability that the NGEIR Decision was intended to provide. As discussed in paragraph 18, in the NGEIR Decision the OEB stated that maintaining a perpetual call on Union's current capacity is not consistent with forbearance.

2.2 Benefits to Gas Users

36. A robust storage market at Dawn provides significant benefit to ratepayers in Ontario and across the North American natural gas market. For example, during Winter Storm Uri in February 2021, production freeze-offs in the U.S. midcontinent resulted in several suppliers calling force majeure on their contracted deliveries of

gas to Enbridge Gas and other shippers on the Panhandle Eastern Pipeline, which is used by Enbridge Gas to transport gas to Dawn. The Dawn Hub provided security of supply to Ontario consumers with increased storage withdrawals to offset upstream supply shortfalls. A robust storage market at Dawn provided benefits to gas users by avoiding system outages and providing some price stability during peak conditions.

37. A more recent example of the benefits of a robust storage market at Dawn to ratepayers is Winter Storm Elliott. This storm swept across North America between December 22 and December 26, 2022, triggering massive blackouts, thousands of cancelled flights, and covering roads in much of Canada and the U.S. in sheets of ice and snow. The deep freeze also had an impact on the pipelines that move natural gas around North America, including those that bring supply to Dawn. Appalachian gas producers experienced widespread production freeze-offs which resulted in significant force majeures called on supply transactions downstream of these producers. Enbridge Gas received notices of force majeure impacting over 230 TJ of supply deliveries contracted to flow to Dawn. Enbridge Gas was able to maintain service to its in-franchise customers amid the lost supply using significant withdrawals from storage at the Dawn Hub.

38. On December 24, 2022, a single-day record of 6.5 PJ/d was withdrawn from storage at Dawn. In addition to allowing Enbridge Gas to serve its customers, these storage withdrawals also provided stability in the price of gas at Dawn during Winter Storm Elliott. Dawn prices increased approximately $0.50 US/Dth ($0.64 CAD/GJ) through the week leading up to the holiday storm whereas nearby market hubs in the U.S. Midwest and U.S. Northeast increased by $10 - $25 US/Dth ($13 - $32 CAD/GJ).

2.3 Consumer Protections in the Competitive Storage Market

39. In the NGEIR proceeding, the OEB and intervenors explicitly contemplated what would happen should Union eventually use the entirety of the 100 PJ of cost-based utility storage space. The 100 PJ cap on storage space was estimated to be fully utilized between 2012 and 2024 based on various growth scenarios. As outlined above, under current OEB-approved methodologies, the actual utilization of storage space is still below 100 PJ and is not forecasted to be fully utilized until the end of this decade which is more conservative than what was contemplated by the OEB at the time of the NGEIR Decision.

40. To date, Union has not required the entirety of the 100 PJ of cost-based storage space to serve its in-franchise customers. This excess utility storage space was sold in the open market on short-term contracts. As directed by the OEB in NGEIR, the margin for short-term transactions that use temporarily available excess utility storage space accrues to the ratepayers.

> The Board finds that the entire margin on storage transactions that are underpinned by "utility asset" storage space, less an appropriate incentive payment to the utilities, should accrue to ratepayers. Ratepayers bear the cost of that space through the regulated storage rates and should benefit from transactions that utilize temporarily surplus space. The Board finds that shareholders will retain all of the margin on short-term transactions arising from the "non-utility" storage space.[26]

41. In examining the issue of what remedy in-franchise customers have should the 100 PJ cap of storage space be exceeded, the OEB clarified that it expects Union to

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[26] EB-2005-0551, Decision with Reasons, November 7, 2006, p.101.

seek incremental storage space above the 100 PJ by procuring such services from the market. The OEB stated:

> No “remedy” is required. Once the 100 PJ limit is exceeded, incremental in-franchise storage requirements will be met through purchases by Union in the open market, a market the Board has determined is competitive. The all-in cost for in-franchise consumers for storage services will be a blend of historical costs for 100 PJ and competitive market prices for the balance.[27]

42. In the NGEIR Decision, the OEB committed to developing a reporting mechanism and complaint process[28] to ensure customer protection within the competitive storage market. Subsequently, the OEB issued the Storage and Transportation Access Rule (STAR) on December 9, 2009. STAR established Posting and Protocol Requirements and Reporting Requirements for Storage companies including Customer Index and storage capabilities. Today, STAR continues to ensure a level of transparency and customer protection within the competitive storage market.

3. Changes Since Amalgamation

43. As outlined in Phase 2 Exhibit 4, Tab 2, Schedule 1, the total in-franchise storage space requirement of Enbridge Gas is the combination of the in-franchise storage space requirements of the customers of the existing individual utilities. In other words, the amalgamation of EGD and Union has not impacted the total demand for natural gas in Ontario and therefore has not impacted the storage space required to serve in-franchise customers. As outlined in Phase 2 Exhibit 4, Tab 2, Schedule 9,

[27] EB-2006-0322/EB-2006-0340, Decision with Reasons, July 30, 2007, p.9.
[28] EB-2005-0551, Decision with Reasons, November 7, 2006, Executive Summary p.2.

Table 1, the total market-based storage space requirement has not increased since before amalgamation.

44. As outlined in Phase 2 Exhibit 4, Tab 2, Schedule 9, Table 1, the EGD rate zone's requirement for storage space beyond its cost-based storage entitlement was 21.3 PJ at the time of the NGEIR Decision and has increased by 4.7 PJ to 26.0 PJ. This increase from 21.3 PJ to 26.0 PJ is reflective of the increase in total number of EGD rate zone customers from approximately 1.8 million to 2.3 million (28% increase). The increase of 4.7 PJ represents a 4% increase in EGD's total in-franchise storage space requirement since NGEIR.

45. Enbridge Gas has proposed in this proceeding to use the entirety of its 199.4 PJ of cost-based storage space to serve in-franchise customers, which would eliminate any excess utility storage.

46. If in-franchise storage requirements decrease in the future, including through impacts of the energy transition, or if natural gas market prices shift such that the financial and risk reduction benefits of using storage no longer outweigh its cost, Enbridge Gas has the flexibility to de-contract market-based storage services that it holds. This eliminates the risk ratepayers would face in owning these assets. If Enbridge Gas were to obtain or develop incremental cost-based storage space, it would seek to recover the full cost of the asset in rate base. For these reasons, Enbridge Gas does not believe this to be a desirable alternative to continuing to purchase excess in-franchise storage space requirements from the competitive storage market. Purchasing market-based storage services versus developing new storage space increases flexibility within the Gas Supply Plan, as storage services are typically purchased with terms of one to five years whereas the development of new storage space would require a long-term capital commitment.

4. Summary

47. Enbridge Gas continues to provide 199.4 PJ of cost-based storage space service to in-franchise customers as established in the NGEIR Decision. Enbridge Gas asserts that the 199.4 PJ cap on cost-based storage space provided to in-franchise customers remains appropriate.

48. In its NGEIR Decision, the OEB determined that EGD in-franchise customers would continue to receive service at cost-based rates for all 99.4 PJ of EGD storage space.

49. Union reserved 100 PJ of cost-based storage space to provide service to in-franchise customers. Under current OEB-approved methodologies, the actual utilization is still below 100 PJ and is forecasted to be fully utilized by the end of the decade.

50. The OEB was clear in the NGEIR Motion Decision that "the purpose of the 100 PJ cap is to establish a permanent allocation between utility and non-utility storage"[29] (emphases added).

51. The NGEIR Motion Decision provided further clarity that the OEB anticipated that:
    a) Union would eventually reach the 100 PJ cap on its cost-based utility storage space;
    b) Union would then procure any incremental storage space requirements from the market; and
    c) The OEB could not foresee how a re-examination of the cap could be justified.

[29] EB-2006-0322/0340 Decision with Reasons, July 30, 2007, p.7.

52. As intended, the NGEIR Decision facilitated competition in the sale of gas to users and the rational development and safe operation of gas storage in Ontario, during which the OEB protected the interests of consumers with respect to prices and the reliability and quality of gas service.

53. Following the NGEIR Decision, significant investment has been made to grow storage capabilities at the Dawn Hub in Ontario. This has increased the overall depth and liquidity of the market at Dawn which provides value to all Ontario natural gas customers by way of competitive commodity pricing and attracting natural gas supply to the province.

54. Ratepayers are not harmed by remaining at 199.4 PJ. In fact, by contracting for storage space requirements above the 199.4 PJ in the competitive market, ratepayers benefit from the significant flexibility that these storage contracts provide. Should in-franchise storage space requirements decrease in the future, these storage contracts can be amended or terminated, and ratepayers would cease to pay for those services.

55. For these reasons, the OEB should maintain the 199.4 PJ cap on cost-based storage space provided to in-franchise customers.

MARKET-BASED STORAGE PROCUREMENT

AMY MIKHAILA, DIRECTOR GAS SUPPLY

DAVE JANISSE, MANAGER GAS SUPPLY ACQUISITION

1. Enbridge Gas has provided this evidence to reflect the following issue that is being addressed in Phase 2 of this Application.

    48) Is the purchase of storage service at market-based rates by Enbridge Gas from Enbridge Gas for in-franchise customers appropriate?

2. The purpose of this evidence is to support Enbridge Gas's current processes for purchasing storage services to serve in-franchise customers at market-based rates as appropriate, which includes purchases by Enbridge Gas from Enbridge Gas's non-utility operation.

3. As outlined in Phase 2 Exhibit 4, Tab 2, Schedule 1, Table 2, a total of 227.7 PJ of storage space is required to support in-franchise customer needs in the 2024 Test Year. Of this requirement, 199.7 PJ will be met using Enbridge Gas cost-based storage space as determined in the OEB NGEIR Decision[1].[2] Since Enbridge Gas requires more than the 199.7 PJ of cost-based storage to serve in-franchise customers, Enbridge Gas is proposing to continue to purchase the remaining 28.0 PJ of storage in the market at market-based prices, consistent with the OEB NGEIR Decision[3] as discussed in Phase 2 Exhibit 4, Tab 2, Schedule 8. It is in the interest of all in-franchise customers that Enbridge Gas be permitted to purchase storage

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[1] EB-2005-0551, OEB Decision and Order, November 7, 2006.
[2] Includes 199.4 PJ of cost-based storage at Dawn, discussed in Phase 2 Exhibit 4, Tab 2, Schedule 5, section 1, plus 0.3 PJ of cost-based storage related to the Crowland storage facility.
[3] EB-2005-0551, OEB Decision and Order, November 7, 2006.

services on their behalf from all market participants, including Enbridge Gas's non-utility operation.

4. Enbridge Gas has been purchasing market-based storage services from third parties as well as its own non-utility operation for many years using a competitive request for proposal (RFP) process that prioritizes cost-effectiveness, reliability, and operational flexibility. Removing any party's eligibility to participate in this competitive process is not in the best interests of Enbridge Gas's ratepayers as this undermines the ability for the process to select the most cost-effective, reliable, and flexible service available in the marketplace.

5. The Company was purchasing storage services at market-based rates for many years prior to the OEB NGEIR proceeding. Prior to the NGEIR proceeding, EGD purchased storage services from Union at market-based rates under the terms of an OEB-approved rate schedule.[4] Union has been selling storage services at market-based rates since 1989. To protect ratepayer interests, the Company has followed formal processes to ensure storage services were procured in a cost-effective manner. Upon the merger of Enbridge Inc. and Spectra Energy Corp in 2017, EGD implemented a blind RFP process, managed by an independent third-party, to continue to protect ratepayer interests. This process recognizes that a portion of the storage services procured annually came from Union, which became an affiliate of EGD through its common parent company, Enbridge Inc. The blind RFP process continued after the amalgamation of EGD and Union. Since 2017, the

[4] EB-2005-0551, Decision with Reasons, p.13: "Union Gas sold storage to both in-franchise and ex-franchise customers. As a generalization, in-franchise customers paid cost-based rates for the storage services they used and ex-franchise customers paid market-based prices. Prices for both groups of customers were regulated by the OEB. However, the prices for ex-franchise customers were subject to OEB-approved maximum rates that were high enough that they would not constrain the pricing of services to ex-franchise customers."

Company has made several process enhancements related to the blind RFP to ensure that there is no ability for Enbridge Gas to give preferential treatment to bids received by Enbridge Gas's non-utility operation. This process has been subject to review in the 5-Year Gas Supply Plan and subsequent Annual Updates from 2020 through to today.

6. This evidence is organized as follows:
    1. Overview of Historical Market-Based Storage Purchasing and Processes
    2. Blind Storage RFP Process
    3. Summary

1. <u>Overview of Historical Market-Based Storage Purchasing and Processes</u>

7. The Company has been purchasing storage services at market-based rates for the EGD rate zone since before the OEB NGEIR Decision in 2007. Market-based storage services are required when total storage requirements for in-franchise customers exceed the cost-based storage allocated to in-franchise customers. A description of the OEB NGEIR Decision[5] and the resulting allocations of cost-based storage to EGD and Union rate zone in-franchise customers can be found at Phase 2 Exhibit 4, Tab 2, Schedule 8. At the time of the OEB NGEIR Decision[6], EGD required 21.3 PJ of storage service in excess of its utility storage capacity, whereas Union had excess utility storage capacity and therefore had no need to acquire market-based storage services.

8. To protect ratepayer interests and ensure market-based storage services were procured in a cost-effective manner, Enbridge Gas has purchased market-based

[5] EB-2005-0551, OEB Decision and Order, November 7, 2006.
[6] Ibid.

storage services using an RFP process. An RFP consists of a formal communication to the market of the amount of storage required and key contractual terms sought by the prospective buyer. Prospective sellers then respond to the RFP by providing formal bids. RFP processes are an effective way for buyers to gain price transparency when negotiating for the purchase of goods or services and provide evidence that buyers are transacting at market-representative prices.

9. As described above, in 2017, Enbridge Inc., the parent company of EGD, and Spectra Energy Corp, the parent company of Union, amalgamated to form Enbridge Inc., creating an affiliate relationship between EGD and Union. In recognition of this affiliate relationship and to ensure no preferential treatment was given by EGD to Union in its annual storage RFP, the Company implemented a blind RFP process whereby an independent third-party was hired to manage the storage RFP. The blind RFP process continued after the amalgamation of EGD and Union. Detailed information about this blind RFP process and enhancements made since 2017 can be found in Section 2.

10. Currently, Enbridge Gas holds 26.0 PJ of market-based storage as part of its overall storage requirement for in-franchise customers. Based on its 2024 Test Year Forecast and the recommendations from ICF, Enbridge Gas proposes to increase the amount of market-based storage purchased for in-franchise customers to 28.0 PJ. Information on how Enbridge Gas determines the amount of storage required for in-franchise customers is provided at Phase 2 Exhibit 4, Tab 2, Schedule 1.

11. Table 1 provides a summary of the market-based storage held by the Company since 2007. Prior to 2007, EGD purchased all of its storage requirements in excess

of its cost-based storage from Union at market-based rates under the terms of an OEB-approved rate schedule.

Table 1
Market-Based Storage Purchased from Union/EGI Non-utility and Other Market Participants

Line No.	Storage Year (PJ)	Storage Purchased from Union/EGI non-Utility	Storage Purchased from Other Market Participants	Total Storage Purchased	Proportion of Union/EGI non-Utility Storage Purchased
		(a)	(b)	(c) = (a) + (b)	(d)
1	2007/2008	21.3	0.0	21.3	100%
2	2008/2009	19.3	2.0	21.3	91%
3	2009/2010	18.3	4.1	22.4	82%
4	2010/2011	18.3	4.1	22.4	82%
5	2011/2012	18.3	4.1	22.4	82%
6	2012/2013	18.3	4.1	22.4	82%
7	2013/2014	13.3	9.4	22.7	59%
8	2014/2016	14.3	9.4	23.7	60%
9	2015/2016	15.1	9.4	24.4	62%
10	2016/2017	16.6	7.9	24.5	68%
11	2017/2018	16.5	7.9	24.4	68%
12	2018/2019	19.5	6.9	26.4	74%
13	2019/2020	18.5	7.9	26.4	70%
14	2020/2021	17.5	9.0	26.5	66%
15	2021/2022	17.5	8.7	26.1	67%
16	2022/2023	17.5	8.5	26.0[7]	67%

12. As outlined in Table 1, the proportion of the market-based storage services portfolio consisting of storage from Enbridge Gas's non-utility operation has declined from 100% at the time of the OEB NGEIR Decision to approximately 67% in the

[7] The 2023 actual storage purchased was 26.0 PJ. The 2023 forecast of total storage purchased was 26.1 PJ as provided at Phase 2 Exhibit 4, Tab 2, Schedule 1.

2022/2023 storage year. This diversification of storage suppliers through the competitive RFP process has benefited ratepayers by providing the most cost-effective, reliable, and flexible service available in the marketplace.

2. Blind Storage RFP Process

2.1. Initial Blind RFP Process

13. In 2017, Enbridge Inc. and Spectra Energy Corp amalgamated, creating an affiliate relationship between EGD and Union. In recognition of this affiliate relationship and to ensure no preferential treatment was given by EGD to Union or any other affiliate in its annual storage RFP, EGD implemented a blind RFP process whereby an independent third-party was hired to manage the storage RFP.

14. The steps of the initial blind RFP process are summarized as:
    a) EGD engaged the external RFP manager and provided relevant training;
    b) EGD provided the RFP letter to the RFP manager which explained the RFP process and requirements, bid template and distribution list of potential participants;
    c) On the agreed upon date, the RFP manager sent the RFP announcement letter and template via email to the provided distribution list;
    d) If the participants had questions, they were directed to the RFP manager who provided the questions to EGD omitting the party name;
    e) EGD responded to the questions and the RFP manager provided responses to the entire distribution list ensuring all participants benefited;
    f) Participants submitted their bids;
    g) The RFP manager compiled all bids into a single anonymous template and submitted them to EGD for evaluation;

h) EGD evaluated the bids (primarily based on price and quality of service) and selected the top-ranked bids;
i) EGD confirmed the accuracy and completeness of the anonymized information for the top-ranked bids by validating bid details with the RFP manager. If required, bids were re-ranked;
j) EGD confirmed winning bids, obtained participant contact information from the RFP manager and notified the successful participants; and
k) EGD's contracting process was commenced.

15. The blind RFP process was discussed during the Enbridge Gas 5 Year Gas Supply Plan Stakeholder Consultation.[8] During this stakeholder conference, several parties were concerned that the blind RFP process may not be entirely "blind", and therefore, the process did not effectively ring-fence Enbridge Gas's gas supply procurement group from its own non-utility storage in the Union South rate zone and its affiliates in Ontario. The specific concern related to step i) above. As part of the confirmation and follow-up questions between Enbridge Gas and the RFP manager to confirm the accuracy and completeness of the anonymized bid information, there were some instances where Enbridge Gas was able to determine the identity of bidders prior to confirmation of winning bids. In the final OEB Staff Report to the OEB, OEB staff supported Enbridge Gas undertaking a third-party independent expert assessment of its blind RFP process by a party that has natural gas experience.[9]

[8] EB-2019-0137.
[9] EB-2019-0137, Final OEB Staff Report to the Ontario Energy Board, March 26, 2020, pp.32-33.

2.2. Post-amalgamation Blind RFP Process Enhancements

16. In response to the stakeholder concerns, Enbridge Gas subsequently made several enhancements to its blind RFP process. These enhancements were discussed in the Enbridge Gas 2020 Annual Gas Supply Plan Update[10], and are summarized as:

   a) As part of the process to engage an RFP manager, Enbridge Gas will make best efforts to hire an RFP manager with gas industry experience. This enhancement results in having an RFP manager that is better equipped to understand submissions, reliably provide accurate information to Enbridge Gas as part of the blind RFP process, and ultimately make an independent recommendation for winning bids;

   b) Bids submitted by participants are now provided to the RFP manager in a standard format, in Canadian dollars and in GJ. Transportation costs are also rolled into the overall cost of storage prior to being provided to Enbridge Gas. This enhancement limits opportunities for bid conversion and interpretation errors, changes the focus of Enbridge Gas's review of bids to analysis rather than validation of unit conversion, and results in a more efficient RFP process overall. This enhancement also reduces bias by eliminating information from the bid process that could identify participants; and

   c) At the launch of the blind RFP process, Enbridge Gas now provides a recorded information session for all prospective participants. This enhancement helps participants understand the importance of Enbridge Gas blind RFP requirements and clarifies expectations up front with participants as a measure to ensure bids are submitted as requested, which reduces requirements for the RFP manager to validate bid information.

[10] EB-2020-0135, pp.8-10.

17. Enbridge Gas hired ScottMadden Management Consultants (ScottMadden) in the spring of 2020 to conduct an independent assessment of the blind RFP process. ScottMadden provided its final report on October 9, 2020, which is included as Attachment 1.

18. ScottMadden's key recommendations were:
    a) Expand the criteria and requirements for choosing an external RFP manager;
    b) Define and document the roles and responsibilities of Enbridge Gas and the external RFP manager;
    c) Revise the RFP letter, bid template and bid instructions to increase clarity and reduce follow up questions from RFP bidders;
    d) Extend the bidding period to allow bidders more time to submit bids; and
    e) Have the external RFP manager conduct bid evaluations and provide rankings and recommendations to Enbridge Gas.

19. Enbridge Gas incorporated all the recommendations from the ScottMadden Report into the blind RFP process and has been using this enhanced process since January 2021.

20. The ScottMadden Report and the resulting enhancements to the blind RFP process were discussed in the 2021 Annual Gas Supply Plan Update[11]. No concerns were raised by stakeholders regarding the enhanced blind RFP process and OEB staff has not communicated any concerns with the process since their report in 2019.

[11] EB-2021-0004, pp.6-7, and Appendix B.

2.3. Current Blind RFP Process

21. The steps of the current blind RFP process are summarized as:

a) Enbridge Gas engages the external independent RFP manager and provides relevant training. Enbridge Gas selects an RFP manager with gas industry experience. Once an RFP manager has been selected, the engagement letter clearly defines the roles and responsibilities of Enbridge Gas and the external RFP manager;

b) Enbridge Gas provides the blind RFP letter to the RFP manager which explains the RFP process and requirements, the standardized bid template, bid evaluation criteria, and the distribution list of potential participants;

c) Enbridge Gas provides a recorded information session for all prospective participants. The information session is posted to Enbridge Gas's website so that participants can access the information at any time during the process;

d) On a date determined by Enbridge Gas, the RFP manager sends the RFP announcement, letter and bid template via email to the provided distribution list;

e) Should the participants have questions, they are directed to the RFP manager who provides the questions to Enbridge Gas omitting the party name and any other information that would identify the potential bidder;

f) Enbridge Gas responds to questions and the RFP manager provides responses to the entire distribution list ensuring all participants benefit;

g) Participants submit their bids using the standardized bid template. All bid information is submitted in Canadian dollars and GJ;

h) The RFP manager anonymizes and ranks the bids and provides a recommendation based on the criteria sent to the RFP manager in step 2 above. The RFP manager may contact Enbridge Gas if questions arise about the application of bid information to the criteria during the bid evaluation. Anonymity of bid information is maintained throughout these communications;

i) Enbridge Gas accepts the RFP manager recommendation, obtains participant contact information from the RFP manager, and notifies the successful participants; and
j) Enbridge Gas's contracting process commences. After successful bids have been confirmed with bidders, all participant information is provided to Enbridge Gas from the RFP Manager.

22. The blind RFP process has been strictly followed as it has evolved. Since the implementation of the recommendations made by ScottMadden detailed above, Enbridge Gas has accepted the RFP manager's recommendations as written with no interaction with bidders prior to acceptance of bids.

2.4. Blind RFP Evaluation Criteria

23. Enbridge Gas has developed evaluation criteria for the selection of market-based storage bids that are sent to the RFP manager as part of each blind RFP. These criteria ensure that the RFP manager ranks and recommends bids such that Enbridge Gas's market-based storage portfolio is reliable, cost-effective, and meets the needs of the Gas Supply Plan.

24. The bid evaluation criteria include minimum requirements for bid eligibility. These minimum requirements are outlined in the RFP letter sent to potential bidders. The minimum requirements are:
    a) Storage service must start by April or May of the requested year;
    b) Storage service must include firm injections from the months of May through September;

c) Storage service must include firm withdrawals from the months of December through March;
d) Bids must be expressed in CAD/GJ/year; and
e) Injections and withdrawals must be nominated at Dawn. This does not mean that physical storage is required to be provided at Dawn. A service provider could provide a storage service without any physical storage assets or by using physical storage assets located outside of Dawn coupled with transportation or other means to accept delivery (injection) or to redeliver volumes at Dawn (withdrawal).

25. In addition to the minimum requirements outlined above, Enbridge Gas has evaluation criteria related to price, injection and withdrawal flexibility, contract term length, deliverability, operational flexibility, and supplier diversity. Detailed evaluation criteria are market-sensitive and therefore are not disclosed in the RFP letter sent to potential bidders. However, once minimum requirements have been met, price and injection/withdrawal flexibility are the primary evaluation metrics used in the selection of winning bids. These criteria are determined ahead of the RFP process and are used by the RFP manager to independently evaluate bids and provide a recommendation to Enbridge Gas.

3. Summary

26. Enbridge Gas purchases market-based storage services which are required when total storage requirements for in-franchise customers exceed the cost-based storage allocated to in-franchise customers per the OEB NGEIR Decision[12].

[12] EB-2005-0551, OEB Decision and Order, November 7, 2006.

27. Enbridge Gas owns non-utility storage at Dawn and sells storage services at market-based rates to many utilities, marketers, gas producers, and commercial and industrial customers located within Ontario, Québec, eastern Canada, the U.S. midcontinent, and the U.S. Northeast.

28. Enbridge Gas's blind RFP process for acquiring market-based storage services is appropriate to ensure that the most cost-effective and reliable services are being procured by Enbridge Gas on behalf of its ratepayers, and that no bias towards Enbridge Gas's own non-utility operation or the services of its affiliates influences the Company's procurement decisions. The blind RFP process allows Enbridge Gas to appropriately include its own non-utility storage services within the competitive process to select storage services.

29. As outlined in the evidence above, Enbridge Gas has been purchasing market-based storage services from third parties as well as its own non-utility operation for many years using a competitive RFP process that prioritizes cost-effectiveness, reliability, and operational flexibility. Removing any party's eligibility to participate in this competitive process is not in the best interests of Enbridge Gas's ratepayers as this undermines the ability for the process to reliably select the most cost-effective, reliable, and flexible service available in the competitive marketplace.

30. For these reasons, Enbridge Gas's current processes for purchasing storage services for in-franchise customers at market-based rates, which includes purchases by Enbridge Gas from Enbridge Gas's non-utility operation using the blind RFP process described herein, are appropriate.

Natural Gas Storage Blind RFP Process

Prepared for Enbridge Gas, Inc.

October 9, 2020

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1. INTRODUCTION

ScottMadden, Inc. ("ScottMadden") was retained by Enbridge Gas Inc. ("EGI" or the "Company") to review and provide recommendations regarding the annual blind bid process used by the Company to conduct, and evaluate responses to, a request for proposal ("RFP") for natural gas storage capacity (the "Blind RFP Process"). ScottMadden understands that the Ontario Energy Board Staff ("OEB Staff") in its Final OEB Staff Report to the Ontario Energy Board ("OEB"), dated March 26, 2020, in Case No. EB-2019-0137 ("OEB Staff Final Report") stated the following regarding the Company's Blind RFP Process:

- "The process is not entirely "blind" and therefore, the process does not effectively ring fence Enbridge gas supply procurement group (who are making the decision to purchase market-based storage) from its own non-utility storage in the Union South rate zone and its affiliates in Ontario.
- The process as currently designed does not eliminate concerns of possible bias."[1]

As a result of these observations, OEB Staff recommended that the Company retain an independent expert with natural gas experience to review and assess the current Blind RFP Process; specifically, OEB Staff stated:

> "As per the draft OEB Staff Report, OEB staff supports Enbridge undertaking a third-party independent expert assessment of its blind RFP process, by a party that has natural gas experience. However, regardless of the outcome of a third-party assessment, OEB staff recommends that Enbridge refine its process so that follow-up requests with the RFP Manager are eliminated. One way to do this is to retain an RFP Manager that has natural gas expertise and the RFP Manager provides Enbridge with the winning storage proposal only. This will eliminate any concerns of bias. OEB staff recommends that Enbridge, in its 2020 Annual Update, report on its progress to refine the current blind RFP process."[2]

Based on a review of the concerns and directives identified in the OEB Staff Final Report, ScottMadden has evaluated and documented the current process used by EGI to administer the Company's Blind RFP Process, and has detailed recommendations regarding the planning and execution of the EGI Blind RFP Process in the sections that follow. To undertake our review and analysis, ScottMadden used the following approach:

- <u>Document the Current Process</u> – as a first step, ScottMadden conducted a review of various documents used in the current Blind RFP Process, including the bidder documents and the spreadsheet used to compare and evaluate the bids. In addition, ScottMadden discussed the process with certain EGI personnel involved in the Blind RFP Process.
- <u>Review and Assess Bid Evaluation</u> – in this second step, ScottMadden reviewed the quantitative approach used to evaluate the bids.
- <u>Narrative Report</u> – in the third and last step, ScottMadden developed this narrative report, which summarizes our understanding of the EGI Blind RFP Process and provides recommendations that support an improved process and address the OEB Staff observations regarding the current process.

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1 Final OEB Staff Report to the Ontario Energy Board – Consultation to Review Natural Gas Supply Plans – EB-2019-0137, dated March 26, 2020, at 32.

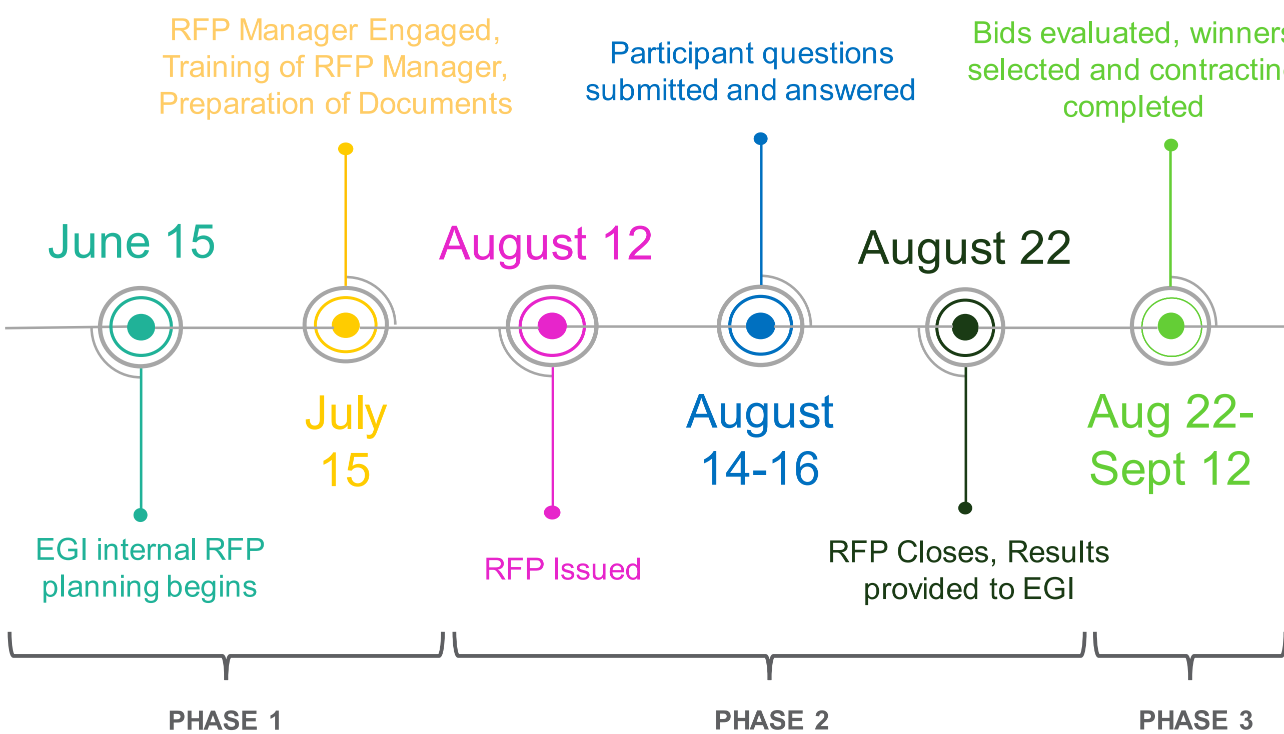
2 *Ibid.*, at 33.

2. OVERVIEW OF CURRENT EGI BLIND RFP PROCESS

EGI, given the level of non-utility natural gas storage it owns and operates,[3] conducts an annual Blind RFP Process with respect to contracting for natural gas storage capacity. To administer this process, and to maintain anonymity of bidders and limit potential bias, the Company contracts with an independent third-party manager (the "External RFP Manager") to help conduct and manage the Company's Blind RFP Process.

To provide the appropriate context and summarize the overall Blind RFP Process, the timeline of activity associated with the Company's 2019 Blind RFP Process is provided below as Figure 1.

Figure 1: EGI 2019 Blind RFP Timeline[4]



Based on ScottMadden's review of the 2019 Blind RFP Process, the timeline of activities spanned approximately 13 weeks. As shown at the bottom of Figure 1, ScottMadden has categorized the activities associated with the Blind RFP Process into three distinct phases, specifically:

- Phase 1 (i.e., planning stage) included activities leading up to the issuance of the RFP and covered the period from June 15 to August 12, 2019 (i.e., approximately 8 weeks);
- Phase 2 (i.e., implementation stage) consisted of approximately 2 weeks of activities from the issuance of the RFP on August 12, 2019, the bidders' question and answer stage, and the

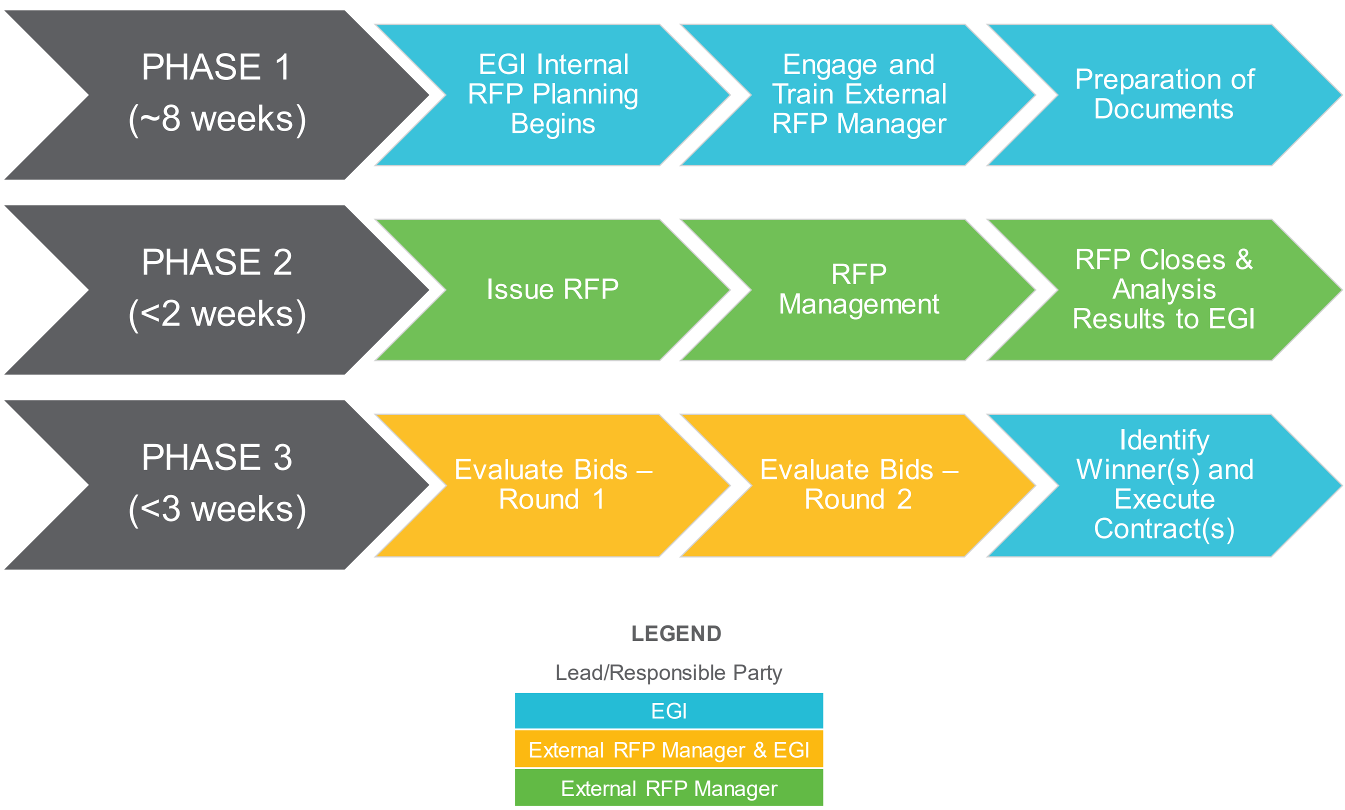
3 *Ibid.*, at 14.
4 Source: Company provided.

closing of the RFP; and concluded with certain information for all bids provided to EGI, on August 22, 2019; and

- Phase 3 (i.e., assessment stage) involved the evaluation of bids, selection of winner(s), and execution of associated natural gas storage contract(s), which occurred from August 22 through September 12, 2019 (i.e., approximately 3 weeks).

In Figure 2 below, ScottMadden has documented, at a high level, the major activities within each phase of the current Blind RFP Process and identified the lead, or responsible party, for those activities, recognizing that certain activities were conducted by both EGI and the External RFP Manager.

Figure 2: Current EGI Blind RFP Process Flow Chart and Roles



As illustrated in Figure 2 above, for the most recent Blind RFP Process, activities shaded in blue were managed by EGI; activities shaded in green were led by the External RFP Manager; and activities that were conducted by both EGI and the External RFP Manager are shown in yellow. Based on our review of the Blind RFP Process conducted in 2019, and given the concerns and directives associated with the bid process outlined in the OEB Staff Final Report (discussed in Section 1 above), ScottMadden has documented the specific tasks associated with the various major activities within each phase and has specific recommendations regarding the planning, implementation, and assessment stages of the EGI Blind RFP Process as discussed in Section 3 below.

3. SCOTTMADDEN'S BLIND RFP PROCESS RECOMMENDATIONS

A. Phase 1 Activities

The Blind RFP Process Phase 1 activities (i.e., planning stage) are conducted prior to the issuance of the RFP and are all led and managed by EGI. Specifically, as shown in Figures 3A and 3B below, the major activities in Phase 1 are currently: (i) the Company's internal RFP planning, (ii) the Company's process of engaging and training the External RFP Manager, and (iii) the preparation of supporting bid documents for the Blind RFP Process.

Figure 3A: EGI Blind RFP Process – Current Phase 1 Activities

EGI Internal RFP Planning Begins

1. Outline requirements for External RFP Manager
2. Identify potential External RFP Managers
3. Assess third-party vendors and contract with External RFP Manager

Engage and Train External RFP Manager

1. Training provided to External RFP Manager by EGI
   - Training may include approaches to identifying and including certain unique cost attributes of natural gas storage costs (e.g., incorporating transportation costs in the total price of the storage service for bid evaluation)
2. Explanatory documents provided to External RFP Manager
   - RFP process and requirements
   - Bid Template (in Excel) and bid evaluation spreadsheet
   - Distribution list of potential bidders/recipients

Figure 3B: EGI Blind RFP Process – Current Phase 1 Activities

Preparation of Documents

1. Identify bidder/recipient list
2. Outline bid objectives
   - Location of service - at the Dawn Hub; transport from the storage facility that underpins the bid to the Dawn Hub must be included in bid price
   - Storage volume
   - Daily deliverability
   - Term diversity
3. Develop screening criteria
   - Lowest cost storage offering at Dawn
   - Flexible injection and withdrawal parameters
   - Term offered compliments existing contract expiry profile
   - Unit cost
   - Flexibility in service
4. Develop supporting bid documents
   - RFP announcement
   - RFP letter with bid instructions
   - Bid Template (in Excel) and bid evaluation spreadsheet

Based on a detailed review of the first two activities in Phase 1 (shown in Figure 3A above), ScottMadden has the following process recommendations for the Blind RFP Process:

- Expand the criteria and requirements for choosing the External RFP Manager, which may include:
    - Knowledge of and/or expertise in natural gas markets;
    - Experience in natural gas storage rate, cost, and service analysis;
    - Familiarity with regulatory requirements and associated processes;
    - Understanding of the need for, and intent of, a "blind" bid process to preserve the anonymity of bidders and limit potential bias; and
    - Ability to manage a bidder process (e.g., management of bidders' questions and answers).
- Outline a detailed process schedule from training of the External RFP Manager to issuance of the RFP to the evaluation of bids and final recommendation(s); and
- Define and document the role and responsibilities of EGI and the External RFP Manager:
    - Meet with the External RFP Manager to confirm and document the Blind RFP Process objectives, overall timeline and schedule, and project team responsibilities; and
    - Develop communication protocols for (i) external communications to the market; (ii) internal communications among the project team; and (iii) project management responsibilities.

In addition, as part of Phase 1, ScottMadden has the following recommendations regarding the preparation of supporting documents associated with the Blind RFP Process (shown in Figure 3B above):

- With respect to the bidder/recipient list:
    - Identify primary and secondary contacts for each bidder/recipient on the list; and
    - Eliminate duplication of bidders.
- Provide a timeline/schedule in the RFP announcement and RFP letter that summarizes the RFP milestones and deadlines;
- Provide a common set of assumptions or requirements (e.g., all bids must be submitted in Canadian dollars per gigajoule (CAD/GJ)) for bidders in the Bid Template (in Excel);
- Request additional information to support bid evaluation (e.g., a total annual cost metric for each bid submitted)[5] in the Bid Template (in Excel); and
- As part of the RFP supporting bid documents, revise the RFP letter and bid instructions to:
    - Include a requirement that bidders must provide one conforming bid; and
        - If conforming bid is submitted, alternative structures may also be submitted;

[5] As discussed further below, the total annual cost metric provided by bidders will be compared to the total annual cost calculated by the External RFP Manager to confirm costs are appropriately modeled and understood.

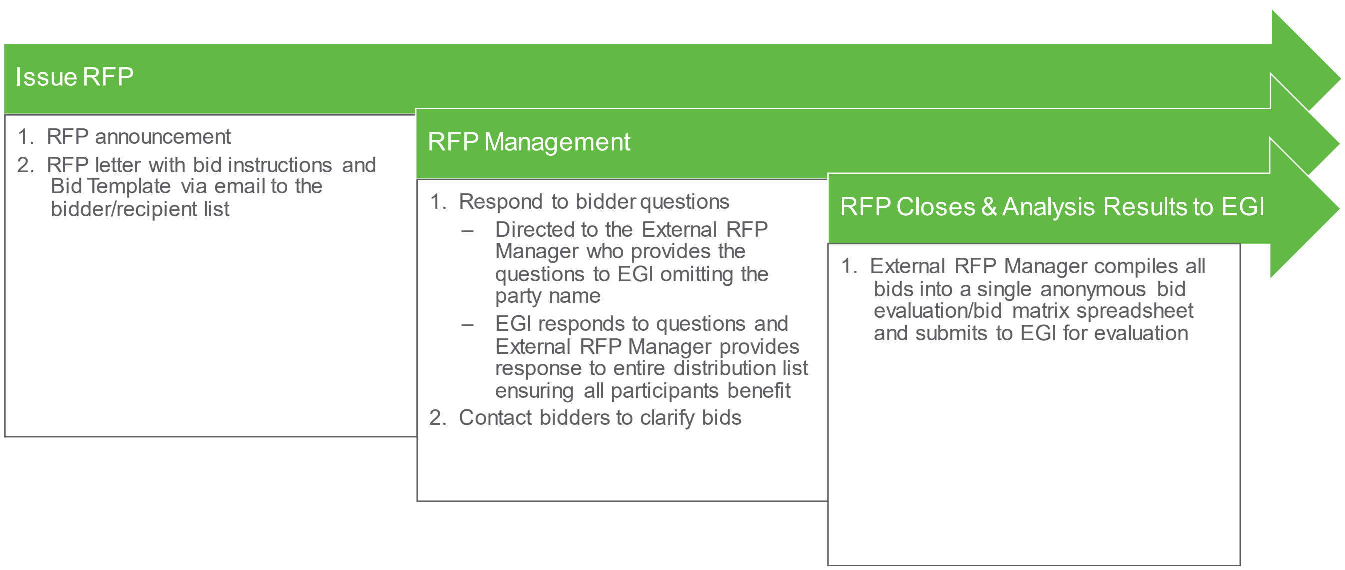
- Request sample monthly invoices from bidders as part of bid submissions – one for an injection month and one for a withdrawal month for each bid submitted.[6]

Please note, a more detailed review of the Bid Template and other supporting bid documents is provided in Sections 3.C. and 3.D, which summarize the ScottMadden recommendations regarding the current process used to evaluate bids.

B. Phase 2 Activities

As shown in Figure 4 below, the current Phase 2 major activities (i.e., implementation stage) of the EGI Blind RFP Process, which are conducted and managed by the External RFP Manager, include: (i) issuance of the RFP; (ii) RFP management and coordination of bidder questions and associated Company responses; and (iii) closing of the RFP and compilation of certain bid information to EGI for evaluation.

Figure 4: EGI Blind RFP Process – Current Phase 2 Activities



Based on ScottMadden's review of the current Phase 2 activities in Figure 4, there are certain modifications that may be implemented by the Company to improve the overall approach and process of the Blind RFP Process. Specifically:

- Conduct a workshop with potential bidders prior to the issuance of the RFP to communicate the objectives of the RFP and describe the RFP process and requirements, which may include a review of the Bid Template and an outline of the timeline/schedule;

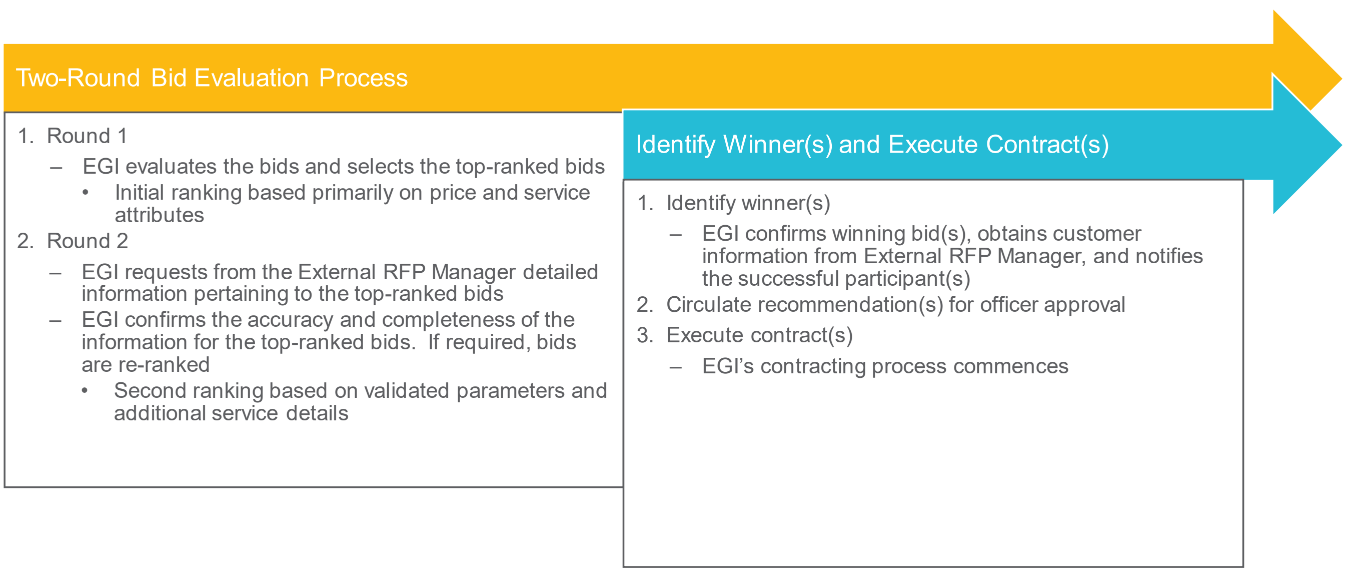
6 As discussed further below, the sample monthly invoice provided by bidders will be compared to the sample monthly invoice values calculated by the External RFP Manager to confirm costs are appropriately modeled and understood.

- Use the EGI website to publicize the RFP, which may need to be supplemented with emails to potential bidders;
- For communication purposes, include a generic EGI email address for bidder submittals (e.g., RFP responses and bidder questions) in addition to the email address of the External RFP Manager, with the generic EGI email automatically forwarded to the External RFP Manager to maintain anonymity of bidders;
- Extend this aspect of the timeline/schedule, which is currently 2 weeks, to allow bidders more time to submit bids; and
- Modify the evaluation process, Bid Template, and other supporting bid documents, which are further described in Sections 3.C and 3.D below.

C. Phase 3 Activities

The major activities in the current Phase 3 (i.e., assessment stage) of the Blind RFP Process include two rounds of bid evaluations, which are coordinated between the Company and the External RFP Manager, as well as the selection of winner(s) and execution of associated natural gas storage contract(s), which are led by EGI.

Figure 5: EGI Blind RFP Process – Current Phase 3 Activities



To address the concerns outlined in the OEB Staff Final Report, ScottMadden has the following recommendations regarding the current two-round bid evaluation process shown in Figure 5. Specifically:

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- Revise the Bid Template and other supporting bid documents (further discussed in Section 3.D), which will allow the External RFP Manager to conduct Round 1 of the bid evaluations and provide initial rankings and recommendation(s) to EGI;[7]
- After the Round 1 analysis by the External RFP Manager, the Company can review the initial rankings and recommendation(s) and confirm the accuracy and completeness of the top-ranked bids; and
- Conduct Round 2 analysis, if necessary, to obtain additional bid clarification or request refreshed bid submissions for the short-listed bids.

In addition, with respect to the final activity in Phase 3 of the Blind RFP Process illustrated in Figure 5 (i.e., execute contract(s)), ScottMadden recommends that, after the execution of contract(s), the Company may provide feedback to bidders/participants that were not chosen to maintain and manage the commercial relationships between EGI and bidders.

D. Bid Template and Supporting Bid Documents

The Company's current Bid Template, which is completed by bidders and used by the External RFP Manager to populate the bid evaluation/bid matrix spreadsheet, is illustrated in Figure 6 below.

7 Please note, given the major activities in Phase 2, the External RFP Manager has access to all the information submitted by the bidders, which will facilitate their review and evaluation of bids.

Figure 6: EGI Blind RFP Process – Current Bid Template

	EGI Storage RFP		
	EGI defined terms:		
	**Up to 5 years of service commencing April 1, 2020*		
	**Firm Injection Schedule: at a minimum, must include the months of May through September*		
	**Firm Withdrawal Schedule: at a minimum, must include the months of December through March*		
	**Firm Injection Curve rights: at least 0.7% of MSB per day*		
	**Firm Withdrawal Curve rights: 1.2% - 1.5% of MSB per day*		
ROUND 1			
1	*Counterparty*		
2	*offer descriptor (i.e. 1 of 3)*		
3	*TERM (years)*		
4	*Start date*		
5	*MSB (max annual storage balance) units: GJ or MMbtu*		
6	*Demand Charge per unit*		
7	*Commodity Charge per unit*		
8	*Fuel Charge per unit*		
9	*Maximum Firm Injection %*		
10	*Maximum Firm Withdrawal %*		
ROUND 2			
11	*Inject/Withdrawal Location*		
12	*Transportation Charge per unit*		
13	*Injection Curve parameters/ratchets*		
14	*Injection period (firm/interruptible)*		
15	*Additional/Enhanced terms*		
16	*Withdrawal Curve parameters/ratchets*		
17	*Withdrawal period (firm/interruptible)*		
18	*Cycling terms (i.e. unlimited)*		
19	*Nomination Windows*		
20	*Additional/Enhanced terms*		
21	*General Terms and Conditions*		
22	*Additional Comments*		
	* If any above line item is not applicable, please insert N/A		

The first 10 data fields of the current Bid Template, shown in Figure 6 above, are generally used to evaluate bids in Round 1 of the current bid evaluation process; and the data fields in rows 11 through 22 are part of the Round 2 evaluation of bids.

Based on ScottMadden's review of the current Bid Template and bid evaluation process, the following recommendations may improve the anonymity associated with bids, increase the role and contribution of the External RFP Manager, as well as improve the overall process of the Blind RFP Process.

- Revise the Bid Template (in Excel) to require additional data elements and to provide to the bidders a common set of assumptions or requirements, which may include:
    - All bids must be submitted in Canadian dollars (with a requirement that monetary values are rounded to three decimal places);

  - All bids must be submitted in GJ (with a requirement that volumes are rounded to the nearest whole number);
  - All pricing must be equivalent to a price landed at the Dawn Hub (i.e., any firm transport required to deliver to the Dawn Hub must be included in bid); and
  - Add a total annual cost metric (assuming one injection and withdrawal cycle of the storage capacity)[8] as an additional data field to be provided by bidders, which may provide transparency regarding the rate structure of bids (i.e., by requesting a total annual cost metric for each bid, the External RFP Manager would be able to compare its calculated total annual cost to the value(s) provided by the bidder).
- Revise the RFP letter and bid instructions to:
  - Include a requirement that bidders must provide one conforming bid with a note that alternative structures may be submitted; and
  - Request sample monthly invoices as additional documentation from bidders as part of bids (one for an injection month and one for a withdrawal month), which will allow the External RFP Manager to compare its calculated sample monthly invoice to the value(s) provided by the bidder.
- Revise certain activities associated with the bid evaluation process, including:
  - By providing a common set of assumptions or requirements that are consistent for all bidders and requiring more information as part of the initial bid submission, the External RFP Manager is better positioned to conduct Round 1 of the bid evaluations, and provide initial rankings and recommendation(s) to EGI;
  - As part of the Round 1 bid review by the External RFP Manager, expand the evaluation to include additional elements, such as lines 11, 12, 13, 14, 16, and 17, of the current Bid Template (i.e., from Figure 6) and use these additional elements to assess and screen bids (see ScottMadden's recommendations associated with the Bid Template in Figure 7 below); and
  - Use Round 2, if necessary, for limited data requests for certain short-listed bids or alternative bid structures.

8 This allows bids that provide flexibility with respect to injection/withdrawal capabilities (e.g., multiple cycles) to be reviewed on a qualitative basis as an additional data element.

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Figure 7: EGI Blind RFP Process – Recommendations for Bid Template

EGI Storage RFP

EGI defined terms:

**Up to 5 years of service commencing April 1, 2021*

**Firm Injection Schedule: at a minimum, must include the months of May through September*

**Firm Withdrawal Schedule: at a minimum, must include the months of December through March*

**Firm Injection Curve rights: at least 0.7% of MSB per day*

**Firm Withdrawal Curve rights: 1.2% - 1.5% of MSB per day*

ROUND 1

1	Counterparty		
	Primary Contact Name		
	Primary Contact Email Address		
	Primary Contact Phone Number		
2	Offer Descriptor (i.e., 1 of 3)		
3	Term (years)		
4	Start Date		
5	Maximum Annual Storage Balance (MSB) (GJ)		
	Total Annual Cost (assuming one injection and withdrawal cycle of the storage capacity) (CAD/GJ)		
6	Daily Demand Charge per unit of Maximum Storage Quantity (CAD/GJ)		
7	Variable Injection Charge per unit (CAD/GJ)		
	Variable Withdrawal Charge per unit (CAD/GJ)		
8	Fuel Charge per unit (CAD/GJ)		
9	Daily Maximum Firm Injection %		
10	Daily Maximum Firm Withdrawal %		
11	Inject/Withdrawal Location (pipeline receipt or delivery meter name and point identifier)		
12	Daily Transportation Charge per unit (include pipeline transport charges incurred to deliver to Dawn Hub) (CAD/GJ)		
13	Injection Curve parameters/ratchets		
14	Injection Period (firm/interruptible)		
16	Withdrawal Curve parameters/ratchets		
17	Withdrawal Period (firm/interruptible)		

ROUND 2

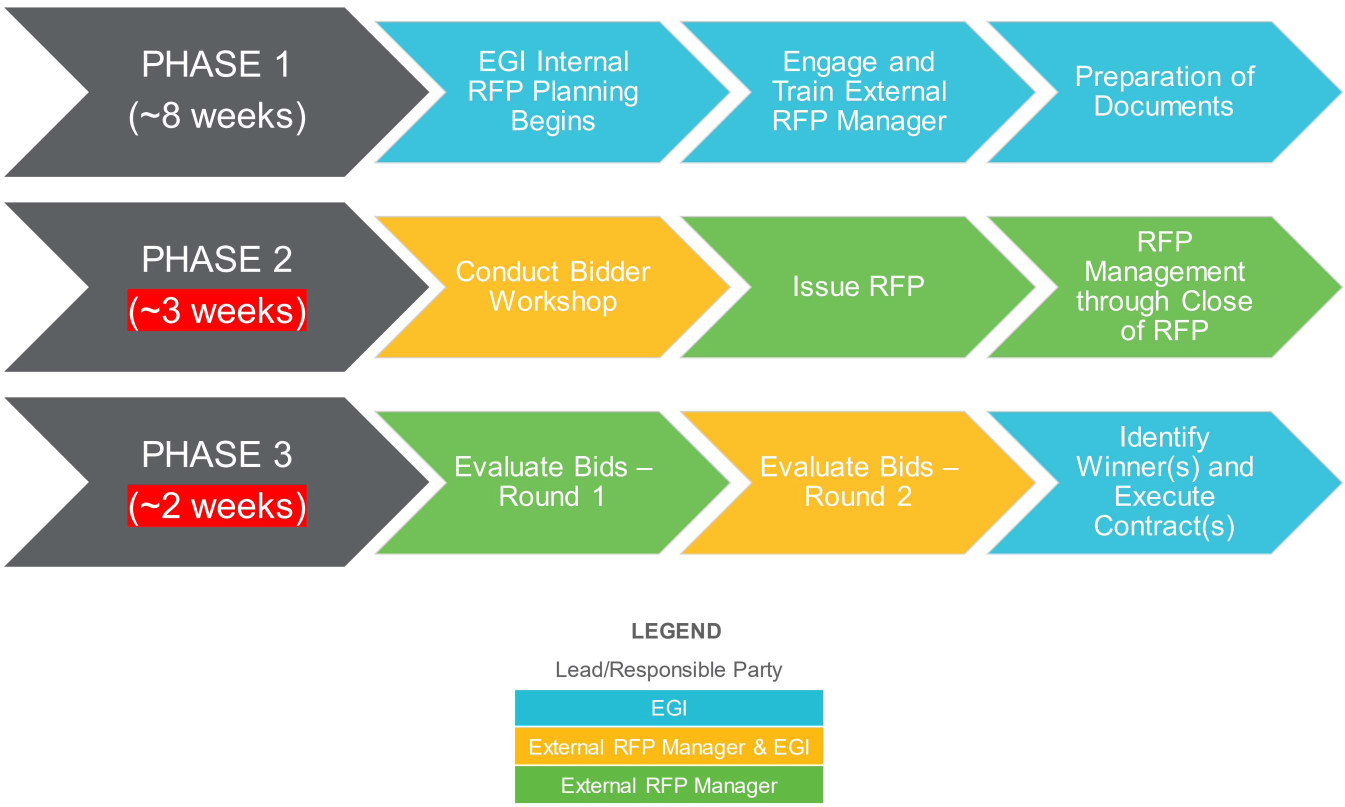
18	Cycling Terms (i.e. unlimited)		
19	Nomination Windows		
20	Additional/Enhanced Terms		
21	General Terms and Conditions		
22	Additional Comments		

* If any above line item is not applicable, please insert N/A

4. SUMMARY AND CONCLUSION

Based on the detailed review and analysis of the current bid process, and considering the directives outlined in the OEB Staff Final Report, ScottMadden has identified several process recommendations associated with each phase of the Blind RFP Process (discussed in Section 3). As a result, Figure 8 below recasts the EGI Blind RFP Process with the inclusion of the ScottMadden recommendations for each phase.

Figure 8: Recommendations for EGI Blind RFP Process Flow Chart and Roles



While ScottMadden does not have changes to the major activities and Enbridge Gas responsibilities associated with Phase 1 (i.e., planning stage), ScottMadden recommends: (i) establishing communication protocols; (ii) expanding the criteria and requirements for selecting and contracting with an External RFP Manager; and (iii) revising certain RFP bid documents in order to facilitate the recommended changes to Phases 2 and 3 of the Blind RFP Process.

With respect to Phase 2 (i.e., implementation stage), ScottMadden's recommendations include extending the timeline/schedule to approximately 3 weeks and conducting a bidder workshop prior to the issuance of the RFP as shown in Figure 8. Please note that the bidder workshop would be a joint activity (i.e., External RFP Manager and EGI) and provides an opportunity to communicate to the bidders the RFP process and associated changes to the process, roles and responsibilities of the External RFP Manager and EGI, and milestones and deadlines. In addition, ScottMadden recommends using the EGI website to publicize the RFP and establishing a generic EGI email address for bidder communications.

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Finally, ScottMadden's process recommendations associated with Phase 3 (i.e., assessment stage) will likely shorten the timeline/schedule for this phase to approximately 2 weeks as illustrated in Figure 8 above. Most notably, ScottMadden recommends revising the Bid Template, which will allow the External RFP Manager to lead the Round 1 evaluation of bids and provide initial rankings and recommendation(s) to the Company. This process recommendation will allow Round 2 to be used, if necessary, to obtain additional bid clarification or request refreshed bid submissions for short-listed bids. Finally, ScottMadden's proposed modifications to the RFP bid documents and bid evaluation process may maintain anonymity of bidders, while allowing EGI to confirm the winning bid(s) and maintain commercial relationships with bidders.

SITE RESTORATION COSTS

MICHELLE TIAN, MANAGER CAPITAL FP&A

1. In the Phase 1 Decision and Order,[1] Enbridge Gas was directed to file evidence indicating how the annual amount for site restoration costs is calculated and to provide a long-term forecast of the total funds required to pay for site restoration costs.

2. The purpose of this evidence is to present Enbridge Gas's calculation and forecast of site restoration costs. This evidence was prepared in response to an OEB-directive from the Phase 1 Decision of this proceeding. Enbridge Gas has accumulated net site restoration costs to date of $1.6 billion.[2] As explained in Phase 1 Exhibit I.1.8-STAFF-17, this balance represents the presumed amount recovered in rates, based on the net salvage component in approved depreciation rates applied to actual gross plant values, less actual removal and site restoration costs incurred, net of any proceeds from disposition, as of December 31, 2022.

3. This evidence is organized as follows:
    1. Calculation of Annual Amounts
    2. Long-Term Forecast of Total Funds Required to Pay for Site Restoration Costs

1. Calculation of Annual Amounts

4. The calculation of the annual site restoration costs recovered through rates is derived by applying the net salvage component in approved depreciation rates to monthly gross plant values.

[1] EB-2022-0200, Decision and Order, December 21, 2023, p.94.
[2] As of December 31, 2022. Phase 1 Exhibit I.4.5-ED-136, part a).

5. The net salvage component in approved depreciation rates effective January 1, 2024, was filed in the Phase 1 Draft Rate Order, Working Papers, Schedule 6, Attachment 1, pages 6 and 7. Net salvage is estimated as a percentage of an asset's original cost to be depreciated and accumulated over the life of an asset. This amount is collected as an added expense to depreciation over the life of an asset. In circumstances where a plant asset is sold, salvage proceeds (or positive salvage amount) are recognized and in circumstances where a plant asset is abandoned or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The estimates of net salvage are based in part on historical retirement activity experienced. Professional judgement also informs the estimates of net salvage by incorporating a review of management's plans, policies and outlook, a general knowledge of the natural gas industry, and comparisons of net salvage estimates of other gas utilities.

6. The net salvage rates are applied monthly to actual gross plant values to calculate the depreciation expense related to net salvage. Historically, there has been a corresponding increase to accumulated depreciation recorded at the same time, which represented an increase to the site restoration cost liability, reducing rate base. Prospectively, the increase to the site restoration cost liability, recognized in conjunction with depreciation expense, will be recorded in the Site Restoration Cost Variance Account (SRCVA). This change is in accordance with the Phase 1 Decision which required that collected net salvage amounts be set aside to fund the site restoration cost liability. The aggregation of the monthly net salvage component in depreciation expense forms the annual provision added to the site restoration cost liability.

7. As decommissioning, site restoration or removal costs are incurred to retire assets, a charge is recorded to draw down the site restoration cost liability. Historically,

these charges were recorded in accumulated depreciation, while prospectively they will be recorded in the SRCVA.

8. Over time the annual site restoration costs based on the net salvage component in approved depreciation rates applied to gross plant values, minus actual removal and site restoration costs incurred, net of any proceeds from disposition, amounted to $1.6 billion as of December 31, 2022. Enbridge Gas prepared a continuity schedule in response to Phase 1 Exhibit I.4.5-IGUA-13, Attachment 1 which provides a 10-year history of Enbridge Gas's annual provision and costs incurred.

9. Table 1 summarizes the calculation of the estimated annual site restoration cost amounts for the 2024 Test Year.

Table 1
2024 Test Year SRC Amounts

Line No.	Particulars ($ millions)	Plant Average Balance (1)	Rate (2)	Provision	Net Salvage Costs	2024 Activity
		(a)	(b)	(c)	(d)	(e) = (c) - (d)
	Underground Storage Plant					
1	Structures and improvements	113.0	0.23%	0.3	0.9	(0.6)
2	Wells	148.3	0.97%	1.4	0.0	1.4
3	Field lines	255.9	0.25%	0.6	0.0	0.6
4	Compressor equipment	741.1	0.20%	1.5	11.2	(9.7)
5	Measuring and regulating equipment	263.8	0.42%	1.1	0.0	1.1
6	Total	1,522.1		4.9	12.1	(7.2)
	Transmission Plant					
7	Compressor Structures and improvements	166.1	0.19%	0.3	0.0	0.3
8	Measuring and Regulating Structures and Improvements	11.4	0.14%	0.0	0.0	0.0
9	Equipment	3.3	0.18%	0.0	0.0	0.0
10	Mains	3,091.3	0.20%	6.2	0.1	6.1
11	Compressor equipment	1,037.3	0.15%	1.5	0.0	1.5
12	Measuring and regulating equipment	491.9	0.23%	1.1	0.0	1.1
13	Total	4,801.3		9.1	0.1	9.0
	Distribution Plant					
14	Services - metal	676.7	0.83%	5.6	4.8	0.8
15	Services - plastic	5,012.2	0.67%	33.5	26.6	6.9
16	Regulators	526.7	0.00%	0.0	2.4	(2.4)
17	Mains - coated and wrapped	3,792.0	0.60%	22.5	8.2	14.3
18	Mains - plastic	3,923.7	0.37%	14.3	9.8	4.5
19	Measuring & regulating equipment	1,025.9	0.35%	2.6	1.5	1.1
20	Meters	1,182.7	0.00%	0.0	0.1	(0.1)
21	Total	16,139.9		78.5	53.4	25.1
22	Total			92.5	65.6	26.9

Notes:
(1) Simple average of the opening and closing plant balances, does not represent actual rate base or plant values.
(2) Phase 1 Draft Rate Order, Working Papers, Schedule 6, Attachment 1, pp.6-7.

2. Long-Term Forecast of Total Funds Required to Pay for Site Restoration Costs

10. Long-term forecasts of total funds required to pay for site restoration costs were prepared by Concentric and the results of the modelling are summarized in Table 2 and Table 3.

11. Concentric has projected the retirement patterns and the estimated timing and magnitude of future collections of net salvage costs for Enbridge Gas's plant assets using plant balances that were in-service as of December 31, 2021, and the average service lives, Iowa curves and net salvage collections that were approved in the Phase 1 Decision. To provide a range of possible future outcomes, forecast future net salvage costs required to retire assets were modelled under two separate scenarios: 1) net salvage estimates as approved in the Phase 1 Decision (low end of range), and 2) Enbridge Gas's actual historical net salvage activity (high end of range). The analysis was also performed with the following simplifying assumptions:
    - No new plant is added after the 2021 depreciation study year;
    - All retirements occur according to the Iowa curve estimate; and
    - There is no inflationary adjustment reflected in the future cost of removal amounts.

Table 2
Total Site Restoration Costs – OEB-Approved Net Salvage

Line No.	Particulars ($ millions)	Total Site Restoration Costs Required to Retire Assets as at Dec 31, 2021	Net Site Restoration Costs Already Collected as at Dec 31, 2021	Site Restoration Costs Collected Between 2022 and 2050	Uncollected Site Restoration Costs at 2050	Net Salvage Costs Incurred Between 2022 and 2050
		(a)	(b)	(c)	(d)	(e)
1	Storage - Wells	71.6	24.5	36.5	10.5	24.9
2	Storage - Compressor equipment	68.2	22.6	34.2	11.4	27.2
3	Transmission - Mains	417.5	100.7	185.3	131.4	131.2
4	Transmission - Compressor equipment	50.3	17.0	33.4	(0.2)	24.1
5	Transmission - Measuring and regulating equipment	39.6	11.7	21.2	6.7	17.0
6	Distribution - Services - metal	274.8	114.3	145.9	14.6	81.4
7	Distribution - Services - plastic	1,783.6	584.9	751.1	447.6	605.5
8	Distribution - Mains - coated and wrapped	1,328.2	375.5	517.9	434.9	416.3
9	Distribution - Mains - plastic	870.0	218.1	319.1	332.8	272.2
10	Distribution - Measuring & regulating equipment	142.6	43.8	80.4	18.5	53.0
11	Other	79.1	29.9	37.7	11.7	27.3
12	Total	5,125.5	1,543.0	2,162.7	1,419.9	1,680.1

Table 3
Total Site Restoration Costs – Actual Historical Net Salvage

Line No.	Particulars ($ millions)	Total Site Restoration Costs Required to Retire Assets as at Dec 31, 2021	Net Site Restoration Costs Already Collected as at Dec 31, 2021	Site Restoration Costs Collected Between 2022 and 2050	Uncollected Site Restoration Costs at 2050	Net Salvage Costs Incurred Between 2022 and 2050
		(a)	(b)	(c)	(d)	(e)
1	Storage - Wells	329.2	24.5	36.5	268.2	114.7
2	Storage - Compressor equipment	109.2	22.6	34.2	52.4	43.5
3	Transmission - Mains	2,310.1	100.7	185.3	2,024.0	725.9
4	Transmission - Compressor equipment	281.4	17.0	33.4	231.0	135.0
5	Transmission - Measuring and regulating equipment	186.0	11.7	21.2	153.1	79.9
6	Distribution - Services - metal	395.7	114.3	145.9	135.5	117.3
7	Distribution - Services - plastic	3,210.4	584.9	751.1	1,874.4	1,089.8
8	Distribution - Mains - coated and wrapped	1,759.8	375.5	517.9	866.5	551.5
9	Distribution - Mains - plastic	800.4	218.1	319.1	263.2	250.4
10	Distribution - Measuring & regulating equipment	237.7	43.8	80.4	113.6	88.3
11	Other	172.8	29.9	37.7	105.0	60.9
12	Total	9,792.7	1,543.0	2,162.7	6,086.9	3,257.2

12. These forecasts are Enbridge Gas's best current estimate and are intended to highlight a range of possible outcomes. In addition, the actual total costs are expected to be higher after factoring in 2022, 2023 and future capital additions, and future inflationary impacts.

13. Using the net salvage estimates approved in the Phase 1 Decision (Table 2), it is expected that total costs to retire 2021 in-service assets is approximately $5.1 billion and will result in an underfunded or uncollected balance of approximately $1.4 billion if the net salvage trend were to continue at the same pace out to 2050. When using Enbridge Gas's actual historical net salvage activity to project the future cost of retiring assets, Table 3 shows that expected total costs to retire 2021 in-service assets is approximately $9.8 billion and will result in an underfunded or uncollected balance of approximately $6.1 billion if the net salvage trend were to continue at the same pace out to 2050.

14. Table 2 presents a scenario where future costs of removal are based on the depreciation parameters approved in the Phase 1 Decision. In contrast, Table 3 presents a scenario where future costs of removal are based on an average of actual historical cost of removal percentages as presented in Section 7 of the Concentric Depreciation Study filed in EB-2022-0200 Exhibit 4, Tab 5, Schedule 1, Attachment 1.

15. The depreciation parameters approved by the OEB in the Phase 1 Decision yield substantially lower future costs of removal in most accounts (Table 2) than the percentages indicated by the actual cost of dismantlement expenditures incurred throughout Enbridge Gas's long history (Table 3). The estimates presented in Table 3 are more representative of the anticipated future costs and unfunded balance, as they are based on actual historical costs of removal. Under the Phase 1 Decision, it

is expected that by 2050 the approved net salvage percentages will result in an additional under-recovery of $4.7 billion for the assets in-service as of December 31, 2021, compared to the recovery that would be required based on a history of actual expenditures.

16. This exhibit presents two simplistic long-term forecasts of total funds required to pay for site restoration costs. As Enbridge Gas conducts a further study on the risk of stranded assets and future costs to salvage assets for its next rebasing application, these forecasts, including estimates of potential uncollected site restoration costs, will continue to be refined.

RATE DESIGN PROPOSALS

DANIELLE DREVENY, MANAGER RATE DESIGN

1. Enbridge Gas has updated this evidence to reflect the following issues that are being addressed in Phase 2 of this Application:

    52) Are the specific proposed parameters for an Energy Transition Technology Fund and associated rate rider appropriate?

    53) Are the specific proposals to amend the Voluntary RNG Program and to procure low-carbon energy as part of the gas supply commodity portfolio, appropriate?

2. The purpose of this evidence is to request OEB approval of two new rate riders.

3. This evidence is organized as follows:
    1. Energy Transition Technology Fund (ETTF)
    2. Low-Carbon Voluntary Program (LCVP)

1. Energy Transition Technology Fund

4. Enbridge Gas is proposing a new ETTF to be used to advance and accelerate research, development, and commercialization of low-carbon technologies. Enbridge Gas is proposing the rate rider be effective with the first QRAM following the OEB Phase 2 Decision. Enbridge Gas is proposing Rider N – Energy Transition Technology Fund Rider be used to recover the cost of the ETTF as described in this section of the evidence. A description of the ETTF proposal is provided at Phase 2 Exhibit 1, Tab 10, Schedule 7.

5. Enbridge Gas proposes to recover the ETTF equally from 2025 to 2028 at a forecast annual amount of $5 million. Enbridge Gas proposes that the rate rider be effective with the first QRAM following the Phase 2 Decision, such that the rate rider and the monthly customer bill impact are consistent with future years. Should the rate rider be implemented after January 1, 2025, due to timing of the Phase 2 Decision, the forecast amount to be collected in 2025 is expected to be less than $5 million. Enbridge Gas has allocated the $5 million annual amount to rate classes based on the number of customers. This allocation methodology is being proposed so that each customer contributes equally to the development of low-carbon energy solutions.

6. Enbridge Gas proposes to recover the ETTF from customers as a fixed monthly amount through a rate rider to the monthly customer charge. The fixed monthly amount has been derived by dividing the rate class allocation by the number of customers and then divided by 12 months of the year. The ETTF unit rates will recover $5 million annually on a forecast basis.

7. The ETTF allocation and derivation of unit rates is provided at Attachment 1. The allocation of the ETTF is based on the total number of in-franchise distribution customers. The ETTF unit rate is $0.11 per month or approximately $1.32 per customer annually.

8. Attachment 2 provides the ETTF rate rider for each rate class which has been included as Rider N – Energy Transition Technology Fund Rider. Enbridge Gas proposes to update the ETTF rate rider each year to reflect the forecast number of customers as part of the annual rate application during the IR term.

9. For rate classes that do not have a monthly customer charge, Enbridge Gas proposes to charge the ETTF rate rider as a one-time adjustment annually at the equivalent of $0.11 per month. This treatment is consistent with the approach for collection of the charge for Bill 32 and Ontario Regulation 24/19 for rate classes without a monthly customer charge.

2. Low-Carbon Voluntary Program

10. Enbridge Gas is proposing a new LCVP for large volume sales service customers. Please see Phase 2 Exhibit 4, Tab 2, Schedule 7, for a description of the LCVP proposal and associated bill impacts.

11. Large volume sales service customers will be able to elect to have some or all of their gas supply be provided by low-carbon energy through the proposed LCVP. Enbridge Gas will charge customers who elect for the LCVP through Rider L – Low-Carbon Voluntary Program.

12. With the introduction of the LCVP, Enbridge Gas will discontinue the existing Voluntary RNG Program, subject to OEB approval in this Application. At that time, the existing Rider L for the Voluntary RNG Program will be updated to reflect the proposed Rider L for the LCVP.

13. The proposed Rider L for the LCVP is provided at Attachment 3. The rate to be calculated for the proposed Rider L will be set to the portfolio average cost per unit of the low-carbon energy procured by the Company that is incremental to the cost of conventional natural gas. The costs of un-elected low-carbon energy will be included in the recovery of the cost of gas supply commodity purchases for at least the duration of the underpinning commodity contracts. Enbridge Gas is requesting

this approval for the LCVP on a permanent basis, until such a time that a change is requested and approved by the OEB.

Derivation of Energy Transition Technology Fund Rider Unit Rates

Line No.	Particulars	2024 ETTF Allocation ($000s) (1)	2024 Forecast Number of Customers	2024 Monthly Charge per Customer ($/month)
		(a)	(b)	(c) = (a/b/12*1000)
	EGD Rate Zone			
1	Rate 1	2,757	2,163,088	0.11
2	Rate 6	220	172,974	0.11
3	Rate 100	0	14	0.11
4	Rate 110	1	416	0.11
5	Rate 115	0	22	0.11
6	Rate 125	0	4	0.11
7	Rate 135	0	41	0.11
8	Rate 145	0	5	0.11
9	Rate 170	0	11	0.11
10	Rate 200 (2)	-	-	-
11	Rate 300 (3)	-	-	0.11
12	Total EGD Rate Zone	2,978	2,336,576	
	Union North Rate Zone			
13	Rate 01	471	369,871	0.11
14	Rate 10	3	2,205	0.11
15	Rate 20	0	62	0.11
16	Rate 25	0	4	0.11
17	Rate 100	0	12	0.11
18	Total Union North Rate Zone	474	372,154	
	Union South Rate Zone			
19	Rate M1	1,536	1,205,199	0.11
20	Rate M2	10	8,077	0.11
21	Rate M4	0	225	0.11
22	Rate M5	0	37	0.11
23	Rate M7	0	61	0.11
24	Rate M9 (2)	-		-
25	Rate T1	0	46	0.11
26	Rate T2	0	41	0.11
27	Rate T3 (2)	-	-	-
28	Total Union South Rate Zone	1,547	1,213,686	
29	Total	5,000	3,922,415	0.11

Notes:
(1) ETTF balance of $5 million allocated to rate classes based on number of customers from column (b).
(2) Wholesale rate classes are excluded from the allocation of the ETTF.
(3) The ETTF rate rider is applicable to rate classes with no forecast of customers.

RIDER: N	ENERGY TRANSITION TECHNOLOGY FUND

APPLICABILITY

This rider is applicable to Customers taking service within the rate classes listed below.

RATES AND CHARGES

	Monthly Charge Per Customer $	
EGD Rate Zone		
Rate 1	0.11	
Rate 6	0.11	
Rate 100	0.11	
Rate 110	0.11	
Rate 115	0.11	
Rate 125	0.11	
Rate 135	0.11	
Rate 145	0.11	
Rate 170	0.11	
Rate 200	0.11	
Union North Rate Zone		
Rate 01	0.11	
Rate 10	0.11	
Rate 20	0.11	
Rate 25	0.11	
Rate 100	0.11	
Union South Rate Zone		
Rate M1	0.11	
Rate M2	0.11	
Rate M5	0.11	
Rate T1	0.11	
Rate T2	0.11	
Rate M4	0.11	Billed annually
Rate M7	0.11	Billed annually

Effective
Implemented
OEB Order EB-2024-0111

Supersedes

RIDER: L	LOW-CARBON VOLUNTARY PROGRAM CHARGE

APPLICABILITY

This rider is applicable to Sales Service Customers in the below rate classes who elect to participate in the Company's Low-Carbon Voluntary Program to fund the incremental cost of low-carbon energy purchased by the Company as part of system supply.

Rate Class

EGD Rate Zone:
Rate 6 (1)
Rate 100
Rate 110
Rate 115
Rate 135
Rate 145
Rate 170

Union North Rate Zone:
Rate 01 (1)
Rate 10
Rate 20
Rate 100

Union South Rate Zone:
Rate M1 (1)
Rate M2
Rate M4
Rate M5
Rate M7

RATES AND CHARGES

The Company will set a rate based on the incremental portfolio price of low-carbon energy (Low-Carbon Energy Fee) that will be applied to each unit of low-carbon energy elected by the Customer. The Low-Carbon Energy Fee (in cents/m³) shall be set to the portfolio average cost per unit of the low-carbon energy procured by the Company that is incremental to the cost of conventional Gas for the duration of the term for each unit of low-carbon energy elected.

MINIMUM TERM

The minimum term available is 12 months from the first delivery of low-carbon energy (Delivery Term) made by the Company to the Customer. The Delivery Term will automatically renew unless the Customer elects a change to the low-carbon energy election for the following Delivery Term subject to the availability of low-carbon energy by the Company.

Notes:
(1) There is a mininum annual consumption requirement of greater than 15,000 m³ for commercial and industrial customers in the Rate 6, Rate 01 and Rate M1 rate classes.

Effective
Implemented
OEB Order EB-2024-0111

Supersedes

ESTABLISHMENT OF NEW DEFERRAL AND VARIANCE ACCOUNTS

JANE HUANG, SUPERVISOR COMMERCIAL/INDUSTRIAL TECHNOLOGIES
JASON VINAGRE, MANAGER REGULATORY ACCOUNTING
RYAN SMALL, TECHNICAL MANAGER REGULATORY ACCOUNTING

1. Enbridge Gas has updated this evidence to reflect the following issues that are being addressed in Phase 2 of this Application.

    32) Is the proposal to close and continue certain deferral and variance accounts and establish new ones appropriate?

    52) Are the specific proposed parameters for an Energy Transition Technology Fund and associated rate rider appropriate?

2. The purpose of this evidence is to request OEB approval to establish three new deferral and variance accounts. The accounts include the Energy Transition Technology Fund Variance Account, described in Section 1, a new OEB Cost Assessment Variance Account, described in Section 2, and an OEB Directive Deferral Account, described in Section 3. The Company has met the OEB eligibility requirements for new deferral and variance account (D&VA) requests as discussed below.

3. The Filing Requirements for Natural Gas Rate Applications (Filing Requirements) require a new D&VA request be accompanied by evidence on how the following eligibility criteria will be met:[1]

[1] Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p.38.

a) Causation – the forecasted expense must be clearly outside the base upon which rates were derived;
b) Materiality – the forecasted amounts must exceed the OEB-defined materiality threshold[2] and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements; and,
c) Prudence – the nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for customers.

4. The proposed Accounting Orders for the new variance accounts are provided at Attachment 1.

<u>1. Energy Transition Technology Fund Variance Account (Account No. 179-339)</u>

5. Enbridge Gas proposes to establish the Energy Transition Technology Fund (ETTF) Variance Account, effective starting in 2025, as a tracking account over the IR term. In order to achieve provincial and federal greenhouse gas (GHG) reduction targets, Enbridge Gas is exploring and pursuing multiple energy transition-related initiatives that will reduce GHG emissions from Enbridge Gas's own operations as well as from buildings, industry, and transportation. A description of these initiatives was provided at EB-2022-0200 Exhibit 1, Tab 10, Schedule 1. As part of its proposed initiatives, Enbridge Gas is requesting approval of the ETTF, which is intended to

[2] The materiality threshold is set at $1 million for a utility with a revenue requirement of more than $200 million, as defined in the Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p.38.

support research, development, and commercialization of low carbon technologies. A description of the proposed ETTF is provided at Phase 2 Exhibit 1, Tab 10, Schedule 7.

6. Enbridge Gas proposes to collect the ETTF through a rate rider, as provided at Phase 2 Exhibit 8, Tab 1, Schedule 2. Collecting the ETTF through a rate rider, as opposed to base rates, provides transparency, as the actual amount collected for the ETTF will be earmarked for the ETTF, underscoring the importance of having a dedicated, continuous, reliable funding stream for technology research and innovation. It also removes the amounts collected for the ETTF from escalation[3] during the IR term. There are no costs associated with the ETTF in the budget underpinning the 2024 Forecast Revenue Requirement that was considered and approved in Phase 1. As a result, the amount forecasted to be collected for the ETTF is incremental to the 2024 Revenue Deficiency, as per Phase 1 of the Application.

7. Enbridge Gas is proposing to collect $5 million forecasted annually from 2025 to 2028. For 2025, the forecast amount to be collected could be less than $5 million due to the timing of the Phase 2 Decision. Enbridge Gas proposes that the rate rider be effective with the first QRAM following the Phase 2 Decision. The actual amount collected through the ETTF rate rider will accumulate in the proposed ETTF Variance Account.

8. As ETTF expenses are incurred, the accumulated balance in the ETTF Variance Account will be drawn down. Since projects funded by the ETTF may straddle

[3] Enbridge Gas is proposing annual rate adjustments using a Price Cap Index during the 2025 to 2028 IR term.

multiple years, the variance account balance will not be considered for clearance until the end of the IR term to allow for continuous, uninterrupted project funding during the IR term.[4] Enbridge Gas intends to align its spending with the amount collected through the proposed rate rider. Enbridge Gas proposes to report on the balance each year in the annual Deferral and Variance Account proceeding, and in the next rebasing application will make a proposal regarding the continuation of the fund and treatment of any outstanding balance at that time.

9. Enbridge Gas has assessed the causation, materiality, and prudence of the ETTF Variance Account:
    a) Causation – All costs that Enbridge Gas intends to record in the proposed ETTF Variance Account are outside of the base upon which rates are derived. The Company is proposing a rate rider to collect the required funding for GHG reduction initiatives.
    b) Materiality – Enbridge Gas's forecasted spend exceeds the $1 million materiality threshold for the establishment of new accounts. The Company is proposing a total of $20 million in ETTF spending, the funding of which will be collected over the IR term and tracked in the variance account. Over time, these funds are intended to support customers and the Company through a period of energy transition.
    c) Prudence – Enbridge Gas's proposed fund for energy transition technology development is critical to address the challenge of climate change and energy transition policies in Ontario and Canada, to satisfy customers' feedback on energy transition, and to deliver the Company's overall energy

[4] Consistent with the principle of ETTF flexibility, as outlined in Phase 2 Exhibit 1, Tab 10, Schedule 7, page 4.

transition plan. Please see Phase 2 Exhibit 1, Tab 10, Schedule 7 for greater detail on the purpose and scope of the proposed ETTF.

2. OEB Cost Assessment Variance Account (Account No. 179-340)

10. Enbridge Gas proposes to establish an OEB Cost Assessment (OEBCA) Variance Account to recover actual incremental OEB cost assessment amounts, as compared to the amount included in rates. The account is proposed to be effective starting in 2024, and to continue through the IR term.

11. The Company acknowledges that as part of Phase 1 of this proceeding, the Company proposed, and it was agreed as part of the approved Phase 1 Settlement Agreement, that the OEB Cost Assessment Variance Accounts that existed for each of the EGD and Union rate zones through 2023 would be discontinued. The purpose of the former accounts, which were directed by the OEB, was to capture material variances in OEB cost assessment amounts that resulted from the application of the revised OEB cost assessment model (effective April 1, 2016), versus the OEB costs reflected in rates which were determined through application of the prior cost assessment model. The impetus for the former accounts (for EGD, Union, and other OEB regulated entities) was the OEB's adoption of a revised cost assessment model, which caused material changes in the apportionment of OEB cost assessment amounts to individual regulated entities, as compared to amounts that would have been assessed using the former assessment model underpinning rates. The impact of the change in apportionment was reflected in Enbridge Gas's 2024 rebasing budget, thus prompting the discontinuation of the former accounts, in alignment with direction provided by the OEB when the accounts were established.

12. The purpose of the proposed new OEBCA Variance Account is to capture material incremental OEB costs assessed to Enbridge Gas, as compared to the amount included in rates, which have risen sharply and are expected to further rise due to significant increases in the OEB's operating budget which is recovered through cost assessments.

13. Enbridge Gas's budget underpinning the 2024 Forecast Revenue Requirement included $9.4 million[5] for OEB cost assessment amounts. This budget amount was developed in Q1 2022 and reflected a moderate inflationary increase over the OEB's 2021/2022 fiscal year (ending March 31, 2022) actual assessed amount of $9.2 million. The OEB's 2021/2022 fiscal year assessed amount was the most current available at the time of budget preparation. A moderate inflationary increase to the 2021/2022 assessed amount was reasonable and appeared aligned with the OEB's then current 2021 to 2024 Business Plan, which forecast an average annual growth of approximately 1.8% in budgeted Total Assessment amounts between its fiscal 2021/2022 and fiscal 2023/2024 years.[6]

14. However, since the time of preparing the 2024 budget, Enbridge Gas has been invoiced OEB cost assessments for each of the OEB's fiscal 2022/2023 and 2023/2024 fiscal years, and each year has seen a material increase well above the budgeted annual assessment increases reflected in the OEB's 2021 to 2024 Business Plan. For the OEB's 2022/2023 fiscal year Enbridge Gas's assessments totalled $11.1 million, an increase of 20.7% over the 2021/2022 fiscal amount, while for the 2023/2024 fiscal year Enbridge Gas's assessments totalled $12.3 million,

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[5] EB-2022-0200, Exhibit I.4.4-STAFF.117 b), the 2024 forecast OEB cost assessments was inadvertently provided as $8.7 million.
[6] OEB 2021-2024 Business Plan, p. 23, Section 26 Financial Plan. https://www.oeb.ca/sites/default/files/OEB-2021-2024-business-plan.pdf

reflecting a further 11.6% increase. Combined, Enbridge Gas's actual experienced assessment increases, before considering further increases expected to be experienced as part of the OEB's 2024/2025 fiscal year assessments, has resulted in a material variance between 2024 assessment costs included in the approved/settled O&M budget and expected actual assessments, of approximately $2.9 million (actual 2023/2024 assessment of $12.3 million less 2024 budget of $9.4 million).

15. The significant increase in actual Enbridge Gas assessed amounts appears to be aligned with government direction and OEB business plans that were released subsequent to the preparation Enbridge Gas's rebasing budget. On October 21, 2022, the Minister of Energy issued a Letter of Direction to the OEB setting an agenda with a number of new initiatives for the OEB.[7] Subsequent to that, the OEB's 2023 to 2026 Business Plan was released in April 2023, which showed more significant annual increases in budgeted Total Assessment amounts (10.82% in 2023/2024 vs 2022/2023, 8.54% in 2024/2025 vs 2023/2024, and 2.04% in 2025/2026 vs 2024/2025), as compared to those which were shown in the 2021 to 2024 Business Plan.

16. The primary driver for the material growth in budgeted Total Assessment amounts is an increase in OEB FTEs, in part attributable to the directives provided in the Minister's Letter of Direction. The OEB's 2023 to 2026 Business Plan indicated that budgeted FTEs increased from 193 in 2021/2022 to 228 in 2023/2024,[8] an increase of 18% over two years. The Business Plan also noted the following:

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[7] Ministry of Energy. (2022 October 21). Letter of Direction from the Minister of Energy to the OEB. https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf
[8] OEB Business Plan 2023-2026, p. 59, https://www.oeb.ca/sites/default/files/OEB-2023-2026-business-plan-en.pdf

- "The new work from the Letter includes the provision of support, guidance and counsel on matters that relate to the Electrification and Energy Transition Panel, reform of the regulatory framework, distribution sector resiliency, responsiveness and cost efficiency, strengthening the performance measurement framework, red tape reduction, and accelerating the adoption of Electric Vehicles across the province."[9]
- "As Minister Smith noted within the Letter of Direction, "the OEB's role as energy regulator has never been more important: the push for further electrification and the transition to cleaner energy sources will require innovation and leadership from the OEB." Accordingly, this Business Plan includes a budget increase to ensure the OEB is appropriately resourced to meet this call to action. The planned actions assume approval of this budget increase to meet resourcing and consulting needs." [10]
- "This financial plan includes additional resources required by the OEB to deliver on its mandate which, when coupled with the Minister's Letter of Direction, involves taking on additional deliverables at a time when the organization is already at full capacity with existing commitments and core adjudicative work. More specifically, this financial plan includes the addition of 25 new permanent FTEs to support our work moving forward."[11]

17. During Enbridge Gas's 2024 calendar (and fiscal) year, the majority of costs that will be assessed by the OEB will be in relation to the OEB's fiscal 2024/2025 year (i.e., one assessment will be for the final quarter of the OEB's 2023/2024 fiscal year, and three assessments will be for the first three quarters of its 2024/2025

[9] Ibid, p. 4.
[10] Ibid, pp.14-15.
[11] Ibid, p.59. Note the 25 new FTEs are incremental to the 2022-2023 Budget of 203 FTEs. There are 35 new FTEs compared to the 2021-2022 Budget of 193 FTEs.

fiscal year). As indicated above, the OEB's 2023 to 2026 Business Plan showed an 8.54% increase in budgeted Total Assessment costs, as compared to the 2023/2024 budgeted amount. This provided an early indication that Enbridge Gas's assessments could increase significantly again, as compared to the actual assessments received in relation to the OEB's fiscal 2023/2024 year, which as noted above were $12.3 million.

18. Developments since the release of the OEB's 2023 to 2026 Business Plan have confirmed that Enbridge Gas's OEB assessments will continue to increase more than could have been forecast.

19. Enbridge Gas is aware that there has been a recent collective bargaining agreement ratified in November 2023 between the OEB and the Society of United Professionals, Local 160, which represents a significant portion of staff at the OEB (164 employees), effective from April 1, 2022 to March 31, 2025, resulting in wage increases of 3% in the first two years and 2% in the third year.[12] As a result, it is reasonable to assume that there are corresponding impacts which were not reflected in the 2023 to 2026 Business Plan, which could result in increases to the OEB's 2024/2025 (and subsequent fiscal years') cost assessments to Enbridge Gas.

20. In April 2024 the OEB released its 2024 to 2027 Business Plan[13] which confirmed the recent cost increases noted above are not temporary. The budget forecast included in this most recent plan indicates higher levels of cost assessment than

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[12] Government of Ontario. (2023 November). Collective Bargaining Ontario. https://www.lrs.labour.gov.on.ca/en/announcements.htm#November2023
[13] OEB Business Plan 2024-2027, https://www.oeb.ca/sites/default/files/OEB-2024-2027-business-plan-en.pdf

previously budgeted. The OEB's 2024 to 2027 Business Plan now shows an 11.25% increase in budgeted Total Assessment costs, as compared to the 2023/2024 budgeted amount (previously 8.54%), which is an increase of 2.5% above the 2023 to 2026 Business Plan for the same period.

21. As noted above, annual OEB cost assessments have increased materially in order to provide the resources the OEB needs to deliver on its mandate and fulfill additional deliverables contained in the Minister's Letter of Direction. The materially increased cost far exceeds a moderate inflationary increase and is expected to deviate significantly from the level expected to be provided through base rates and application of the Price Cap mechanism. As a result, Enbridge Gas believes that variance account treatment of OEB cost assessment amounts is appropriate, as it will allow Enbridge Gas to recover actual annual assessment costs which are beyond its control.

22. Enbridge Gas has assessed the causation, materiality, and prudence of the OEBCA Variance Account:
    a) Causation – Enbridge Gas has included $9.4 million for OEB cost assessments in the budget underpinning the 2024 Forecast Revenue Requirement. Any amounts recorded in the OEBCA Variance Account will reflect actual cost assessment amounts received from the OEB, compared to the amounts included in rates, and as such, are outside of the base upon which rates are derived.
    b) Materiality – Based on Enbridge Gas's most recent cost assessments, and insight provided by the OEB's most recently available Business Plan (2024 to 2027), annual OEB cost assessment amounts anticipated to be received in 2024 (and subsequent years of the IR term) are expected to exceed the

amount included in the 2024 Forecast Revenue Requirement by more than the $1 million materiality threshold for the establishment of new accounts.

c) Prudence – OEB assessment costs are determined by the OEB (outside of the Company's control) in order for it to recover its costs of fulfilling its mandate and deliverables (established in Letters of Direction provided by the Minister), and as such, amounts are assumed to be reasonably incurred, and recoverable from customers.

3. OEB Directive Deferral Account (Account No. 179-341)

23. Enbridge Gas proposes to establish an OEB Directive Deferral Account to record the incremental costs incurred by Enbridge Gas to respond to OEB directives and requirements from this proceeding. The account is proposed to be effective starting in 2024, and to continue through the IR term.

24. Enbridge Gas acknowledges that the OEB stated the following in the Phase 1 Decision:

> The OEB denies Enbridge Gas's request for a new OEB Directive Deferral Account for 2024. This request was first raised in the reply argument with no opportunity for other parties to make submissions on this request. In addition, the proposed basis for this account has not been sufficiently defined. If Enbridge Gas expects to incur significant incremental costs resulting from OEB directives in this proceeding, a deferral account can be requested based on specific cost estimates, subject to meeting the OEB's criteria for establishing new deferral accounts.[14]

25. Since the Phase 1 Decision, Enbridge Gas has reassessed the request and determined that this account will record the costs incurred by Enbridge Gas to

[14] EB-2022-0200, Decision and Order, December 21, 2023, p.126.

respond to OEB directives and requirements from all phases in this proceeding.[15] This would include costs related to each of the Phase 1 directives described in Table 1, including the engagement of experts and/or new internal resources to prepare studies/reports, and to support such studies/reports in applicable future regulatory proceedings,[16] whether known or unknown at this time (e.g. a potential customer revenue horizon and customer attachment policy proceeding).

26. The costs which will be incurred to comply with the OEB's Phase 1 Decision directives (and potentially Phases 2 and 3) are above and beyond the scope of historical expected work requirements. These requirements and associated costs were not anticipated at the time of preparing the Company's budget for the 2024 Test Year.

27. As a result of various directives imposed on Enbridge Gas as part of the Phase 1 Decision, the Company is now forecasting that material and significant costs will be incurred during the IR term. Outlined in Table 1 is a non-comprehensive list of the work required to be completed to address the directives in the Phase 1 Decision and preliminary cost estimates:

[15] Phase 1 (EB-2022-0200), Phase 2 (EB-2024-0111) and Phase 3 (TBD).
[16] Examples of support required include addressing interrogatories, undertakings, appearances at hearings, etc.

Table 1

Directives from Phase 1 Decision and Cost Estimates

OEB Decision / Other Reference	OEB Directive and Anticipated Work	Preliminary Cost Estimates
Phase 1 Decision p.68	Stranded asset risk assessment • Regional scenario analysis, including developing regional profiles, conducting probabilistic modelling and stakeholder engagement to determine the likely energy transition scenario in each region. • Jurisdictional scan – energy transition regulatory and policy scan to identify energy transition and stranded asset risk mitigation techniques being utilized in leading jurisdictions. • Asset system review – evaluating energy transition risks and operational risks in the various scenarios at regional/system level by developing system profiles that include an overview of current asset inventory, asset condition, utilization, anticipated investments (i.e., repairs, replacement, growth). • Energy transition risk and mitigation analysis – review of risks and identification of mitigations, such as adjusting depreciation, extending asset life, IRP measures, etc.	$700,000+ $100,000+ TBD – scope of work and cost estimates impacted by regional scenario analysis and jurisdictional scan TBD – scope of work and cost estimates impacted by regional scenario analysis and jurisdictional scan
Phase 1 Decision p.92	Depreciation study Beyond the scope of a typical depreciation study, the OEB has requested a full review of alternative depreciation methodologies to better mitigate the risk of potential stranded cost. This review will include, but will not be limited to: • Review of the applicability of the Units of Production methodology to the Enbridge Gas system. • Depreciation calculations utilizing the Units of Production methodology. • Depreciation calculations utilizing the Equal Life Group procedure, both with and without an Economic Planning Horizon.	$182,000+

	• Investigation into other depreciation procedures and methodologies to mitigate potential stranded costs, to include the Sum of the Years Digits, Generation Arrangement and shortening of Average Service Life estimates.	
Phase 1 Decision pp.92-93	Net salvage study Study and report on the current approach and costs to salvage assets, alternative approaches to salvage assets and a best estimate of the future costs to salvage assets for the 10 identified accounts.	$1,000,000+
Phase 1 Decision p.101	Overhead capitalization methodology assessment Independent third-party assessment of EGI's overhead capitalization methodology	$350,000+
Phase 1 Interim Rate Order p.11	Long-term investment strategy for funds collected for future site restoration costs • Commission an Asset Liability study to review expected liability obligations, funding amounts from customers and to construct an investment asset mix that is expected to deliver reasonable asset growth to assist meeting future obligations over time, within risk tolerances. • Develop an investment policy formalizing the desired asset mix recommendation, investment objectives and risk tolerances.	$50,000+
Phase 1 Decision and Bill 165 Explanatory Note	The Phase 1 Decision directed a zero-year revenue horizon. Bill 165 would reverse that Decision and retain the current 40-year revenue horizon (depending on the phrasing of supporting Regulations). However, Bill 165 would also require that the OEB make a later determination (prior to January 1, 2029) as to an appropriate revenue horizon. • It is therefore expected, as a result of the Phase 1 Decision and government direction in response that there could be an OEB proceeding addressing customer revenue horizon and whether further changes to gas distributor customer attachment policies are appropriate, taking into account energy transition.	TBD

28. The preliminary cost estimates provided above only consider the costs for preparing the initial reports to be submitted as pre-filed evidence, and do not include the costs of experts' involvement during any applicable discovery phase (e.g., interrogatories; undertakings; appearances at applicable technical conferences, hearings; etc.). Expert costs during the discovery phase are difficult to estimate, however could amount to substantially higher costs in comparison to the cost of the initial estimates. There could also be additional costs for directives arising from subsequent phases in this proceeding (Phases 2 and 3), and any follow-on proceedings taking place during the IR term.

29. Enbridge Gas has assessed the causation, materiality, and prudence of the OEB Directive Deferral Account:
    a) Causation – Enbridge Gas has not included any costs associated with incremental work required to address OEB directives in the budget underpinning the 2024 Forecast Revenue Requirement. Any amounts recorded in the OEB Directive Deferral Account will reflect actual costs incurred as they are outside of the base upon which rates are derived.
    b) Materiality – Based on the above cost estimates, the estimate of costs to be incurred will exceed the $1 million materiality threshold for the establishment of new accounts.
    c) Prudence – any directives imposed on Enbridge Gas by the OEB are outside of the Company's control and as such, amounts are assumed to be reasonably incurred, and recoverable from customers.

ENBRIDGE GAS INC.

Accounting Entries for
Energy Transition Technology Fund (ETTF) Variance Account
Account No. 179-339

This account records the variance between the actual amounts collected to fund energy transition technology initiatives and actual costs incurred for the initiatives.

Simple interest is to be calculated on the opening monthly balance of this account using the OEB-approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the OEB in a future rate application.

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 579 Miscellaneous Operating Revenue
Credit	-	Account No. 179-339 ETTF Variance Account

To record, as a credit in the account, the amount collected to fund energy transition technology initiatives.

Debit	-	Account No. 179-339 ETTF Variance Account
Credit	-	Account No. 728 General Expenses

To record, as a debit/(credit) in the account, the costs incurred to fund energy transition technology initiatives.

Debit	-	Account No. 179-339 ETTF Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit/(credit) in the account, interest expense on the opening monthly balance.

ENBRIDGE GAS INC.

Accounting Entries for
OEB Cost Assessment (OEBCA) Variance Account
Account No. 179-340

This account records the variance between the actual amount of OEB costs assessed to Enbridge Gas, versus the assessment costs included in rates.

Simple interest is to be calculated on the opening monthly balance of this account using the OEB-approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the OEB in a future rate application.

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-340 OEBCA Variance Account
Credit	-	Account No. 728 General Expense

To record, as a debit/(credit) in the account, the difference between the actual annual OEB cost assessment amounts and the forecast cost assessment amount included in rates.

Debit	-	Account No. 179-340 OEBCA Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit/(credit) in the account, interest expense on the opening monthly balance.

ENBRIDGE GAS INC.

Accounting Entries for
OEB Directive Deferral Account
Account No. 179-341

This account will record the incremental costs incurred by Enbridge Gas to respond to OEB directives and requirements resulting from all phases of its 2024 Rebasing proceeding. This would include the engagement of experts and/or new internal resources to prepare studies/reports, and to support such studies/reports in applicable future regulatory proceedings (e.g., responding to interrogatories, hearing appearances, etc.), whether known or unknown at this time (e.g., a potential customer revenue horizon and customer attachment policy proceeding).

Simple interest is to be calculated on the opening monthly balance of this account using the OEB-approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the OEB in a future rate application.

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-341 OEB Directive Deferral Account
Credit	-	Account No. 728 General Expense

To record, as a debit in the account, the incremental costs attributable to OEB directives and requirements incurred during the IR term.

Debit	-	Account No. 179-341 OEB Directive Deferral Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit in the account, interest expense on the opening monthly balance.

INCENTIVE RATE-SETTING MECHANISM

TANYA FERGUSON, VICE PRESIDENT FINANCE & BUSINESS PARTNER
GILMER BASHUALDO-HILARIO, MANAGER DEMAND FORECASTING & ANALYSIS
RYAN SMALL, TECHNICAL MANAGER REGULATORY ACCOUNTING

1. Enbridge Gas has updated this evidence to reflect that the following issues are being addressed in Phase 2 of this Application.

   42) Are the proposed Price Cap Incentive Rate-Setting Mechanism, Annual Rate Adjustment Formula, and term appropriate?

   43) Are the proposed elements of Enbridge Gas's Price Cap Incentive Rate-Setting Mechanism appropriate?

   44) Is the proposed approach to incremental capital funding appropriate?

   45) Is the proposed earnings sharing mechanism appropriate?

   46) Is Enbridge Gas's proposal for annual proceedings for clearance of deferral and variance accounts and presentation of utility results (and any ESM amounts) and scorecard results appropriate?

2. Additionally, following the OEB's Phase 1 Decision, Enbridge Gas has re-evaluated its Incentive Rate-Setting Mechanism (IRM) proposal and has updated the IRM evidence to reflect the impact of the decision, including certain directives that the OEB set out for Enbridge Gas to address in the IRM Application.

3. The purpose of this evidence is to support Enbridge Gas's request for a multi-year IRM to be used to set regulated distribution, transportation, and storage rates for the period January 1, 2025, to December 31, 2028 (IR term), pursuant to Section 36 of the *Ontario Energy Board Act, 1998*, as amended (the Act). Enbridge Gas is proposing rates during the IR term be set based on a Price Cap Incentive Rate-setting (Price Cap IR) mechanism and associated parameters. The OEB's Filing Requirements for Natural Gas Rate Applications state that under a Price Cap IR, "base rates are set through a Cost of Service process for the first year and then adjusted in years two through five using a formula specific to each year (Price Cap IR)".[1] As proposed in this Application, the first year of the IR term will apply the Price Cap IRM parameters to rates set through cost of service for 2024.[2] This IRM proposal is largely consistent with the IRM approved by the OEB and in place over the period 2019 to 2023. The main differences are a proposal for an annual base rate adjustment for capitalized overheads stemming from an OEB directive included in the Phase 1 Decision, and a proposal for a two-factor inflation factor, each of which will be discussed further below.

4. The parameters proposed for the Price Cap IR mechanism, which will be applied to prior year approved base rates, include:
    a) An annual base rate adjustment required to migrate indirect overheads from capital to O&M over the IR term, as directed by the OEB in its Phase 1 Decision;
    b) An annual rate adjustment mechanism, applied to the prior year's approved base rates amended to incorporate the annual base rate adjustment, using a Price Cap Index (PCI) to set rates for 2025 to 2028, where PCI is determined

[1] Filing requirements For Natural Gas Rate Applications, February 16, 2017, p.4.
[2] EB-2022-0200.

by an inflation factor (I), less a productivity factor and a stretch factor (X = Productivity + Stretch);

c) A Y factor adjustment for costs that are incremental to the costs subject to Price Cap escalation, (i.e., pass-through items or costs approved in other proceedings and implemented as part of the annual rate application);
d) A Z factor adjustment to address material changes in costs associated with unforeseen events outside of the control of management;
e) An Incremental Capital Module (ICM) to address incremental capital investment needs;
f) An Off-Ramp Mechanism; and
g) An Earnings Sharing Mechanism (ESM).

5. Enbridge Gas retained Black & Veatch Management Consulting (Black & Veatch) to undertake Total Factor Productivity (TFP) and benchmarking research for an overall X factor (Productivity + Stretch) recommendation and an inflation factor recommendation to support the Company's IRM proposal. The resulting study titled 'Total Factor Productivity, Benchmarking, And Recommended Inflation and X Factors for Enbridge Gas Inc. Incentive Rate-Setting Mechanism' (Black & Veatch Study) has been updated for Phase 2 and is provided at Attachment 1, and the data used to develop the TFP and benchmarking results is provided at Attachments 2 to 4.

6. This evidence is organized as follows:
    1. Price Cap Incentive Rate-Setting Mechanism
    2. Y Factors
    3. Z Factor Adjustments
    4. Incremental Capital Module
    5. Off-Ramp

6. Earnings Sharing Mechanism
7. Annual Adjustment Process and Reporting
8. Customer Protection Measures
9. Deferral and Variance Accounts
10. Considerations for Next Rebasing/IR Term

1. Price Cap Incentive Rate-Setting Mechanism (IRM)

7. The OEB provides two options for natural gas utilities for setting rates: Price Cap IR and Custom IR.[3] Price Cap IR is the standard rate setting approach.[4] Enbridge Gas is proposing a Price Cap IR with an ICM option and associated parameters for the purpose of setting rates during the IR term. Enbridge Gas's proposal is in line with the OEB's expectation that the Price Cap IR should be appropriate for utilities for setting rates.

8. A Price Cap IR provides incentives for the utility to implement comprehensive, longer term productivity improvements which are then passed on to customers at the next rebasing and results in more stable and predictable rates. This method of setting rates will also provide the Company flexibility in managing costs effectively to ensure the continued safe and reliable operation of the gas distribution system. Setting rates under a Price Cap IR is in line with the value customers place on predictable pricing as per Enbridge Gas's customer engagement study conducted by Innovative Research Group which was provided in EB-2022-0200 at Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 10.

[3] Ontario Energy Board Handbook to Utility Rate Applications, October 13, 2016, p.25.
[4] Ibid, Appendix 2, page iii.

9. Enbridge Gas expects that rates set under a Price Cap IR will allow the Company to manage its investment needs and provide an opportunity for the Company to earn the allowed rate of return. A Price Cap IR also allows for potential recovery of incremental capital investment through the ICM mechanism and the potential to address unforeseen items through a Z factor.

10. Under the proposed Price Cap IR mechanism, rates set through Cost of Service for the 2024 Test Year (the first year) will be adjusted in each year of the IR term (years two through five, or 2025 to 2028) to: reflect an annual base rate adjustment, and to apply the Price Cap Formula. 1.

1.1 Base Rate Adjustment

11. Enbridge Gas is proposing the inclusion of an annual base rate adjustment with respect to the change in treatment of indirect overhead capitalization as directed in the Phase 1 Decision, as part of its Price Cap IR mechanism.

12. In the Phase 1 Decision:

> The OEB approves the proposed overhead harmonization methodology, except for the capitalization of indirect overheads. The OEB does not approve the proposal to capitalize $292 million in 2024. However, the OEB recognizes that a requirement to expense the entire $292 million in 2024 would have a large impact on 2024 rates. Therefore, the OEB directs Enbridge Gas to expense $50 million of the indirect overhead amount in 2024, calculate the revenue requirement impact and capitalize the remaining $242 million. In subsequent years, during the IRM term, Enbridge Gas shall reduce the remaining capitalized amount by expensing a further $50 million in each year. For example, in 2025, Enbridge Gas will

expense a further $50 million, reducing the capitalized amount of $242 million to $192 million.[5]

The OEB also found that "an implementation plan is required to migrate the remaining $242 million balance of capitalized indirect overheads to O&M. As part of the IRM issue to be addressed in Phase 2 of this proceeding, Enbridge Gas shall file a proposal to reduce the capitalized indirect overhead balance by $50 million in each year of the IRM term and expense it as O&M."[6]

13. In accordance with the OEB's direction to implement the annual migration of an incremental $50 million in indirect overheads from capital to O&M in rates (or from a cost recovery perspective), the Company is proposing the inclusion of an annual base rate adjustment as part of its Price Cap IR mechanism. The intent of the proposed annual base rate adjustment is to keep rates aligned with the treatment/accounting for indirect overheads ordered by the OEB, and to allow the Company to continue to recover its costs of providing service. The level of cost incurred year-to-year will not be impacted by a change in accounting treatment. However, the change in accounting treatment will cause a revenue requirement impact, as annual overhead expenditures treated as capital are recovered with a carrying charge over time, while expenditures treated as O&M are recovered in the year incurred. The implementation of the proposed base rate adjustment, in conjunction with the directed change in treatment of annual indirect overheads, is needed to ensure that customers continue to pay for the approved costs of providing service (which would not be the case without the proposed base rate adjustment).

[5] EB-2022-0200, Decision and Order, December 21, 2023, p.98.
[6] EB-2022-0200, Decision and Order, December 21, 2023, p.99.

14. The calculations supporting the Company's proposed annual base rate adjustments are provided at Attachment 5, page 1 and reflect changes to the level of capital and O&M as compared to the base amounts reflected in the 2024 Test Year. The adjustments are calculated by first quantifying the cumulative annual revenue requirement impact of increasing O&M by an incremental $50 million in each year of the IR term, offset by the corresponding revenue requirement impact of the cumulative reduction in annual capital amounts. By way of example, the 2025 revenue requirement impact reflects an increase to O&M of $50 million and corresponding capital reduction of $50 million, while the 2026 revenue requirement impact reflects an increase to O&M of $100 million (an incremental $50 million over the amount reflected in 2025) and corresponding cumulative capital reduction of $150 million ($50 million carried forward from 2025 plus an incremental $100 million for 2026). The 2027 and 2028 cumulative revenue requirement impacts are calculated in a similar manner. In determining the capital reduction revenue requirement impacts, the annual capital reductions have been profiled each year in a manner consistent with the $50 million reduction that was reflected in the base 2024 Test Year results to determine the rate base impacts. The 2024 approved capital structure has been used to calculate the carrying charge impacts, and composite depreciation and CCA rates have been utilized to calculate depreciation and income tax impacts. The cumulative annual revenue requirement impacts are provided at Attachment 5, page 1, line 12.

15. Once the cumulative annual revenue requirement impacts are quantified, the change in the annual revenue requirement impacts can be calculated. As the Company is proposing annual base rate adjustments (which carry on in subsequent years), it is these changes in annual revenue requirement impacts that are proposed as the annual adjustment amounts. The proposed annual base rate

adjustments of $56.9 million in 2025, $52.0 million in 2026, $47.1 million in 2027, and $40.7 million in 2028, are provided at Attachment 5, page 1, line 13. The change in the annual revenue requirement impacts decline over the IR term because the anticipated incremental annual capital savings grow each year as the cumulative avoided capital grows, which increasingly offsets the incremental annual O&M increase impact, which remains level each year.

16. Enbridge Gas proposes to allocate the annual base rate adjustment for the indirect overheads to rate classes in proportion to total O&M expenses excluding cost of gas. Please see Attachment 5, page 2 for the proposed allocation of the annual base rate adjustment for the indirect overheads for the years 2025 to 2028. The proposed allocation is based on the last OEB-approved cost allocation studies for the EGD rate zone[7] and Union rate zones.[8] Should the OEB approve a harmonized cost allocation study in Phase 3 of the Application, Enbridge Gas proposes to update the allocation of the annual base rate adjustment as part of a subsequent annual rate application.

17. As the Company proposes to address the migration of overhead from capital to O&M, for rate setting purposes over the IR term, through base rate adjustments, the Company believes the adjustments should be subject to annual Price Cap Index (I – X) escalation under the proposed Price Cap Formula. Escalation of the annual base rate adjustments is appropriate, as the underlying overhead costs will be subject to inflation (net of productivity) pressures, regardless of their accounting and rate treatment.

[7] EB-2017-0086.
[8] EB-2011-0210.

1.2 Price Cap Formula

18. Following the annual base rate adjustment, to set rates during the IR term under the Company's proposed Price Cap Mechanism, the Price Cap Formula will be applied to the amended base rates. The Price Cap Formula can be calculated as (I - X) ± Y ± Z + ICM, where:

    a) I = inflation factor;
    b) X = productivity factor and stretch factor;
    c) Y = costs that are incremental to the costs subject to Price Cap escalation (i.e., pass-through items or costs approved in other proceedings and implemented as part of the annual rate application);
    d) Z = change in costs associated with unforeseen events outside of management control; and
    e) ICM = Incremental Capital Module.

19. In addition to the base rate adjustment and the formulaic changes to rates discussed in this evidence, Enbridge Gas notes that it also proposed rate adjustments for rate mitigation, associated with the implementation of harmonized rate classes and rates, as part of Phase 1 at EB-2022-0200 Exhibit 8, Tab 2, Schedule 6.[9] The need for rate mitigation adjustments are expected to be examined as part of Phase 3.

1.3 Inflation Factor

20. Enbridge Gas proposes to use a two-factor inflation factor for rate escalation during the IR term, consistent with the OEB's 4th Generation IRM Report of the Board, where the inflation factor is calculated as a weighted average of inflation in a labour

[9] Ontario Energy Board Filing Requirement for Natural Gas Rate Applications, February 16, 2017, chapter 2, p.36.

sub-index and a non-labour sub-index.[10] Enbridge Gas proposes that the inflation factor be calculated as the weighted sum of:

a) 75% for the non-labour component (calculated as the calendar year-over-year percentage change in the annual average of Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand (GDP IPI FDD)[11] available for the most recent calendar year), and
b) 25% for the labour component (calculated as the calendar year-over-year percentage change in the annual average of Ontario fixed weighted index of Average Hourly Earnings (AHE)[12] available for the most recent calendar year).

21. Enbridge Gas's proposal for a two-factor inflation factor is guided by the following directions from the OEB:[13]

a) The inflation factor must be constructed and updated using data that is readily available from public and objective sources such as: Statistics Canada, the Bank of Canada, and Human Resources and Social Development Canada,
b) To the extent practicable, the component of the inflation factor designed to adjust for inflation in non-labour prices should be indexed by Ontario distribution industry-specific indices, and

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[10] Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, pp.15-16.
[11] Statistics Canada. (2024 Feb 29). Canada- Price indexes, gross domestic product; Canada; Implicit price indexes; Final domestic demand; 2007=100, Table: 36-10-0106-01 (formerly CANSIM 380-0066), v62307283. https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=3610010601
[12] Statistics Canada. (2024 Mar 28). Fixed weighted index of average hourly earnings for all employees (SEPH), excluding overtime, unadjusted for seasonal variation, for selected industries classified using the North American Industry Classification System (NAICS); Ontario; Industrial aggregate excluding unclassified businesses; Index, 2002=100, Table: 14-10-0213-01 (formerly CANSIM 281-0039), v1606242. https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1410021301
[13] EB-2010-0379, Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario Electricity's Distributor, November 21, 2013, Section 2.1, pp.5-6.

c) The component of the inflation factor designed to adjust for inflation in labour prices will be indexed by an appropriate generic and off-the-shelf labour price index (i.e., not distribution industry-specific).

22. This approach of developing inflation factors was also supported by the OEB in the generic proceeding to review the 2022 inflation factors to be used in the electricity distribution IRM plans.[14] The OEB found that the 4th Generation IRM methodology for developing inflation factors remained appropriate for 2022.

23. In the 4th Generation IRM methodology, the OEB-approved inflation factor applied a 30% weight to the labour sub-index measured by the average weekly earnings (AWE) for workers in Ontario and a 70% weight to the non-labour sub-index measured by the Canadian GDP IPI FDD. This assumption was initially used in the First Generation IRM plans implemented in Ontario in the late 1990s. The OEB noted that the 70% assumption adopted then may now be outdated, but there was insufficient data to refine or update the estimate. Enbridge Gas proposes a 25% weighting for labour and 75% weighting for non-labour because these weights are broadly consistent with the share of non-labor and labor costs for Enbridge Gas and other gas distributors. They are also similar to recent inflation factor precedents in Ontario as discussed in Section 3.2 of the Black & Veatch Study.

24. Enbridge Gas is also proposing to use the fixed weighted index of AHE for the labour sub-index as the AHE is a more representative measure of price inflation for labour inputs than the AWE, and because the AHE is a direct measure of input prices and is more compatible with a Price Cap IR than the AWE.

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[14] EB-2021-0212

25. Enbridge Gas's proposal for the inflation factor is supported by Black & Veatch, as discussed in Section 3.0 of the Black & Veatch Study.

1.4 X Factor

26. The X factor has two components: the productivity factor and the stretch factor. Enbridge Gas proposes a productivity factor of -1.5%[15] and a stretch factor of zero, based on the recommendations from Black & Veatch, as discussed in Sections 4.0 and 5.0 of the Black & Veatch Study.

Productivity Factor

27. The productivity component of the X factor is intended to represent the long run TFP trend for the gas distribution industry. The analysis conducted by Black & Veatch estimates a long-run TFP trend for the gas distribution industry of -1.5% per annum. A negative productivity factor is a result of slowing output growth and increasing input quantity growth, particularly more rapid growth in capital inputs. These trends are observed throughout the gas distribution industry. The study has demonstrated that the productivity factor of -1.5% is generally consistent with the productivity offsets that have been approved for U.S. gas distributors in recent Regulatory proceedings. Black & Veatch's estimated TFP trend is also broadly supported by Pacific Economic Group's (PEG) 2018 TFP Study for OEB staff. PEG's 2018 Study estimates that the negative TFP trend is accelerating (i.e., becoming more negative) over time. Please see Section 6.2 of the Black & Veatch Study for more details.

[15] Actual productivity factor recommendation from the Black & Veatch study is -1.52% but the number is rounded to one decimal place, consistent with the Settlement Agreement in EB-2019-0194, where Enbridge Gas agreed to round PCI to one decimal place.

Stretch Factor

28. The stretch factor component of the X factor is meant to reflect the incremental productivity gains that the utility is expected to achieve during the IR term. The cost benchmarking results from the Black & Veatch Study indicate that Enbridge Gas is a good cost performer and therefore, has less potential to achieve incremental productivity gains than the rest of the industry. Over the last few IR terms, EGD and Union (prior to 2019) and Enbridge Gas (since amalgamation) have been able to realize significant sustainable efficiencies and synergies. These efficiencies and synergies along with further embedded productivity savings were reflected in the 2024 rebasing budget and passed on to customers. In addition, the reduction to O&M spend that was approved as part of the Phase 1 Settlement Agreement,[16] represents further savings passed on to customers as part of 2024 Rebasing. Please see Section 6.3 of the Black & Veatch Study for more details. Based on the results of the cost benchmarking study and the continued benefits to customers from synergies and productivities, Enbridge Gas proposes a stretch factor of zero.

<u>2. Y Factors</u>

29. Enbridge Gas proposes a Y factor cost recovery mechanism for costs that are incremental to the costs subject to Price Cap escalation (i.e., pass-through items or costs approved in other proceedings and implemented as part of the annual rate application). Enbridge Gas will treat the following costs as Y factors:
    a) Cost of gas and upstream transportation: The cost of gas supply, upstream transportation and gas supply balancing will continue to be passed through to customers through the Quarterly Rate Adjustment Mechanism (QRAM).

[16] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.30.

b) Demand Side Management (DSM) costs as determined in DSM proceedings:[17] In accordance with the current treatment, changes to annual DSM Program costs approved as part of DSM Program review process/proceedings will be updated in rates through the annual rate setting application.

c) Lost Revenue Adjustment Mechanism (LRAM): Enbridge Gas DSM programs result in reduction of volume consumption. The utility will continue to adjust the volumes used to calculate rates through the annual rate setting application to capture the impact of DSM activities for contract rate classes (i.e., LRAM volumes).

d) Normalized Average Use Adjustment: Phase 3 is expected to address rate design for all rate classes, including general service. To the extent the OEB approves a Straight Fixed Variable or Straight Fixed Variable with Demand (SFVD) rate design for the general service rate classes[18], upon implementation there would no longer be a need for a normalized average use adjustment. Unless and until the SFVD rate design is implemented, Enbridge Gas will require a Y factor for a normalized average use adjustment.

3. Z Factor Adjustments

30. To address material changes in costs associated with unforeseen events outside of management control, Enbridge Gas is proposing to include a Z factor mechanism as part of the Price Cap IR plan.

[17] Enbridge Gas 2022-2027 Natural Gas Demand Side Management Framework and Plan Application EB-2021-0002, and subsequent proceedings.
[18] EB-2022-0200, Exhibit 8, Tab 2, Schedule 3.

31. Enbridge Gas proposes to follow the criteria as defined in the OEB's Filing Requirements for Natural Gas Rate Applications[19] when assessing whether a Z factor event qualifies for recovery:
    a) Causation – the cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine event and must be clearly outside the base upon which rates were derived.
    b) Materiality – the cost increase or decrease must meet a materiality threshold, in that its effect on the utility's revenue requirement in a fiscal year must be equal to or greater than the established threshold.
    c) Prudence – the cost subject to an increase or decrease must have been prudently incurred.
    d) Management control – the cause of the cost increase or decrease must be:
        i. Not reasonably within the control of utility management
        ii. A cause that utility management could not reasonably control or prevent through the exercise of due diligence.

32. Enbridge Gas proposes a Z factor materiality threshold of $5.5 million, which is the same as the threshold approved by the OEB for Enbridge Gas in its MAADs Decision.[20] Enbridge Gas expects that it would request Z factor treatment of material changes in costs, where those changes meet the listed criteria above. Examples of potential Z factors include significant natural disasters and changes in government policy or legislation.

[19] Filing Requirements For Natural Gas Rate Applications, February 16, 2017, p. 40.
[20] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.

4. Incremental Capital Module

33. Enbridge Gas proposes an ICM as part of the Price Cap IR plan, to recover costs associated with qualifying incremental capital investments beyond what can be funded through approved rates, largely consistent with the OEB-established policy on ICM.[21] Enbridge Gas is proposing a modified approach for ICM funding, where it is proposing to combine the "advanced" element of the Advanced Capital Module (ACM) with ICM as described in Section 4.1. In addition, Enbridge Gas is also proposing a modification to the ICM mechanism in relation to Asset Life Extension (ALE) projects, where such projects would be grouped together for ICM purposes, as opposed to being viewed as discrete projects, and would not be subject to the project specific materiality threshold. The ICM proposal for ALE projects is discussed in further detail at Phase 2 Exhibit 1, Tab 17, Schedule 1.

34. As per the ICM policy, qualifying capital investments are discrete projects that satisfy the eligibility criteria of materiality, need and prudence.[22] The level of capital expenditure that Enbridge Gas will be expected to fund through approved rates will be determined by the OEB's calculation of the ICM materiality threshold value. Where Enbridge Gas's proposed in-service capital budget for a rate setting year during the IR term exceeds the ICM materiality threshold value, it will be eligible to seek ICM funding for qualifying projects.

35. The OEB's ICM multiplier, which is applied to base year depreciation expense to determine the annual materiality threshold is calculated as follows:

[21] Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, and Report of the OEB – New Policy Options for the Funding of Capital Investments: Supplemental Report, January 22, 2016.
[22] Ibid.

Threshold value = $1 + [(RB/d) \times (g + PCI \times (1+g))] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$

where:

a) Rate Base (RB) will be the approved rate base for the 2024 Test Year.
b) Depreciation (d) will be the approved depreciation expense for the 2024 Test Year.
c) Growth (g) will be the percentage difference between the forecasted distribution revenues for the 2024 Test Year and distribution revenue of the most current complete year, expressed as an annual growth rate.
d) Price Cap Index (PCI) is the Price Cap index for the year (% Inflation less productivity factor less stretch factor).
e) Years since rebasing (n) is the number of years since rebasing (2024 Test Year).

36. Enbridge Gas will seek recovery for the revenue requirement associated with capital spend for projects which are above the ICM threshold and meet the ICM eligibility criteria. The revenue requirement calculation will be determined using the cost of capital parameters approved by the OEB for the 2024 Test Year.[23] Further details of Enbridge Gas's requested amended incremental capital funding mechanism are described in Section 4.1.

<u>4.1 ACM/ICM request proposal during the IR Term</u>

37. Within the Phase 1 evidence, Enbridge Gas filed a Utility System Plan (USP) and an Asset Management Plan (AMP) to support the Company's future capital plans. In the Phase 1 Decision, the OEB did not accept the AMP as a basis to support the

[23] The OEB has initiated a generic proceeding (EB-2024-0063) to review the methodology for determining the values of the cost of capital parameters and deemed capital structure to be used to set rates for electricity transmitters, electricity distributors, natural gas utilities, and Ontario Power Generation Inc. The proceeding will also address how any changes to cost of capital parameters and/or deemed capital structure should be implemented.

proposed capital investments and ordered a reduction of $250 million to the overall proposed capital budget for 2024.[24] These elements of the decision, along with a general negative tone towards capital spending in the context of stranded assets, has created uncertainty of capital cost recovery during the IR term and upon rebasing.

38. In light of the Phase 1 Decision, the 2024 Capital Budget of $1.2 billion establishes a new constraint for Enbridge Gas to manage its capital plan and optimize its capital asset portfolio during the proposed IR term. Enbridge Gas will aim to set its annual capital budget at a level consistent with the 2024 approved level of capital, subject to inflationary and growth impacts. This level of capital spend is largely in line with the programmatic spend required to provide safe and reliable service, and customer growth spend required to add customers, except for instances of large, lumpy projects. In order to understand the capital plan, it is important to understand the type of spend that makes up the plan.

39. Programmatic spend is required to sustain safe, reliable, and compliant operations to maintain asset function resulting in ALE and improve operational efficiency and customer service. Examples include investments to meet regulatory compliance and contractual obligations, integrity work, and both reactive and proactive renewal and maintenance strategies. Within programmatic spend are investments focused on ALE which aim to reduce the level and frequency of large-scale replacement projects and that over time will result in less large, lumpy projects. The programmatic portfolio is optimized to balance maintenance, component-level, and full replacement solutions. The preferred solution is informed through maintenance inspections, condition assessment, and demand management programs with

[24] EB-2022-0200, Decision and Order, December 21, 2023, p.58.

mitigation plans giving priority to extending the service life of assets while ensuring safety and reliability.

40. Growth investment includes costs associated with connecting customers (new mains, services, meters and regulating equipment) and distribution system reinforcement, but may exclude large expenditures tied to transmission or distribution growth projects which may be viewed as discrete capital investments.

41. Asset strategies guide the actions required to reduce the potential for asset failures and mitigate the risks associated with these failures. Failure potential is reduced through a combination of preventative maintenance, threat assessment, condition monitoring and damage prevention programs. In cases where an asset is determined to be damaged or has failed, options to repair or replace the asset are considered. Replacement options may be considered if a repair is inviable, for asset relocations, or where an increased risk of failure is expected. The scope of the replacement (component or full) is determined based on cost, risk, and required performance. Where possible, Enbridge Gas employs maintenance and reactive programs to modify asset systems or components to extend asset life where condition monitoring is not technically or economically viable.

42. Enbridge Gas recognizes that it could be required to make significant capital investments in any given year of the IR term, which may cause spending to exceed the ICM threshold. Significant capital expenditures could be required to support Ontario government goals, including the addition of 1.5 million homes by 2031,[25] the pursuit of economic development projects (EV, mining), the pursuit of projects

[25] More Homes Built Faster Act, 2022. https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-23

that reduce emissions (steel, cement, and refining), and large growth projects on the distribution or transmission system. Significant expenditures could also be required to support renewal/lifecycle projects. Where such expenditures cannot be accommodated within the ICM threshold, Enbridge Gas will request incremental funding treatment for these projects through the proposed ACM/ICM mechanism as applicable.

43. Enbridge Gas asset investments will be discussed in greater detail in the 2025 to 2034 Asset Management Plan to be filed with the OEB towards the end of 2024. Also, as directed in the Phase 1 Rate Order Decision,[26] Enbridge Gas will be reporting on the steps that it is taking to achieve the 2024 Capital Budget reduction as part of Phase 3 of this proceeding.

44. To address the concerns with certainty of cost recovery of capital investments, Enbridge Gas is proposing a modified approach to incremental capital (above the ICM threshold) cost recovery using elements of the ACM and ICM tools, as prescribed by the OEB.

45. Both the ICM and ACM in their current forms do not work for the Company for various reasons noted below. The ICM mechanism allows an applicant to file an incremental capital funding request as part of the annual rate application for the year the project is planned to go in service. This timing may not provide reasonable certainty, before significant capital expenditures are made, that the capital expenditure will be eligible for ICM treatment, where ICM requirements are met. The OEB's ICM framework also includes an ACM, where an applicant identifies discrete projects that may qualify for ACM treatment at the time of a cost of service

[26] EB-2022-0200, Decision on Interim Rate Order, April 11, 2024, p.6.

application, establishes the need and prudence for the projects based on its USP and AMP, and provides a preliminary calculation of materiality threshold based on information in its cost of service application. If ACM treatment is granted, in the subsequent price cap rate setting year for which the project goes into service, the applicant provides updated threshold information and a calculation of the rider to be applied. Given that as part of Phase 1, the Company's AMP was not accepted, Enbridge Gas is not able to leverage an AMP in Phase 2 to seek ACM approval for qualifying projects over the IR term.

46. Given the Phase 1 Decision and its findings, Enbridge Gas is proposing to combine the "advanced" element of ACM with ICM, by seeking to file the ICM funding request with the Leave-to-Construct (LTC) application for the relevant project. Advancing the request for ICM treatment, and associated rate rider, within an LTC application is intended to increase certainty of cost recovery. With this timing and a positive LTC decision from the OEB, the Company will have greater certainty of rate recovery at the same time it receives approval to construct the project before significant investment is made.

47. As part of the proposal, where Enbridge Gas anticipates that a large project, subject to LTC approval, will qualify for and could require incremental funding, an ICM request will be included as part of the LTC application. The need and prudency assessment for the ICM request will be made in conjunction with the LTC application. Project specific materiality will be assessed and determined as part of the LTC, along with a preliminary assessment of materiality[27] in the context of the overall capital budget. To support the preliminary assessment of materiality in the

[27] In the MAADs Decision (EB-2017-0306/0307), the OEB determined that individual project for which ICM funding is sought must have an in-service capital addition of at least $10 million.

context of the overall capital budget, and to support the potential need for ICM recovery, Enbridge Gas will file its latest capital forecast/budget and AMP or AMP Addendum, and the forecast ICM threshold using the forecast parameters for the in-service year. Within the LTC application, Enbridge Gas will seek approval for a preliminary ICM rate rider based on the forecast filed in the application. If approved, the rate rider will be updated in the annual rate application for the year in which the project is planned to be in-service, using updated ICM threshold parameters and the latest capital forecast in support of the incremental capital funding request.

48. For ICM qualifying projects that do not require LTC approval (e.g., compressor replacement, facility/building need, IT system), Enbridge Gas will follow the prescribed ICM methodology and request approval for incremental funding as part of the annual rate application for the year that the projects are planned to be in service.

<u>5. Off-Ramp</u>

49. Enbridge Gas proposes an off-ramp where a regulatory review may be triggered in the event actual utility earnings are outside of +/- 300 basis points from the OEB-approved ROE during the IR term.

50. Enbridge Gas is also proposing that an additional off-ramp be included, where a regulatory review could be requested before utility earnings deviations of +/- 300 basis points are realized, where government legislation or policy or a change in OEB policy and requirements causes a change in operating environment/parameters from those upon which base rates were established. Where a change in legislation or policy impacts the Company's operating environment, that is not readily able to be addressed through a Z factor, the

Company (or customers) should not have to wait for a material change in utility earnings to materialize before rates can be adjusted to reflect the new operating parameters. For instance, the Ontario government has indicated it will introduce a Natural Gas Policy Statement as per the recommendation in the Electrification and Energy Transition Panel's Report[28]. The timing, direction and impacts resulting from a Natural Gas Policy Statement are not yet known. Additionally, changes in municipal, provincial, and federal government, or changes in legislation from current governments, could lead to profound changes in policy and wide-reaching impacts on Enbridge Gas. As another example, the likely OEB policy proceeding to review customer attachment policy and revenue horizon for gas distributors could have impacts that are not easily addressed during the IR term. The additional off-ramp will allow Enbridge Gas to adjust to the changing energy policy environment and mitigate risks and uncertainties surrounding the government legislation and policy.

6. Earnings Sharing Mechanism

51. Enbridge Gas proposes an asymmetric ESM in its Price Cap IR plan. The ESM protects customers against excess earnings and allows for sharing of efficiencies that result during the IR term with customers. Enbridge Gas will share utility earnings in excess of 150 basis points above the OEB-approved ROE on a 50/50 basis with customers.

52. Enbridge Gas proposes a continuation of the Earnings Sharing Mechanism Deferral Account (ESMDA) to capture the customer share of utility earnings that result from the application of the earnings sharing mechanism. Rather than accumulating amounts in the ESMDA for disposition at the end of the IR term, Enbridge Gas is

[28] Ontario Clean Energy Opportunity; Report of the electrification and energy transition panel, December 2023, https://www.ontario.ca/files/2024-02/energy-eetp-ontarios-clean-energy-opportunity-en-2024-02-02.pdf

proposing that amounts held in the ESMDA will continue to be disposed of through annual deferral and variance account proceedings. This is consistent with historical treatment of ESM amounts for Enbridge Gas. The ESM mechanism will be applicable for the years 2025 to 2028. Enbridge Gas will file an accounting order, reflecting the approved parameters for the ESMDA, as part of the Draft Rate Order for Phase 2.

7. Annual Adjustment Process and Reporting

53. To set annual rates during the IR term, Enbridge Gas proposes to file the rate application annually in two phases:

a) In Phase 1 of the annual rate application, Enbridge Gas will file an application and supporting evidence including a draft rate order by June 30 in each year[29] during the IR term which reflects the base rate adjustment with respect to the change in the treatment of indirect overhead capitalization, the impact of the PCI, Y factors and requested Z factors. In addition, the draft rate order will include updated service charges, which reflect the application of the PCI to base 2024 service charges,[30] as was provided at EB-2022-0200 Exhibit 8, Tab 3, Schedule 1, consistent with application of PCI to other 2024 base rates. The documentation would be in sufficient detail to allow the OEB to issue a procedural order, such that a final rate order could be issued by November 25 for implementation by January 1.

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[29] Given the timing of the Application, 2025 base rates will be set as part of the Phase 2 draft rate order process. The final 2025 rates will include the outcomes of the Phase 2 Decision effective January 1, 2025.

[30] With exception to the non-sufficient funds (NSF) charge and third-party costs since these charges are directly passed on to the customer.

As explained in Phase 2 Exhibit 1, Tab 3, Schedule 1, Enbridge Gas plans to request approval of the 2025 rates as part of the Phase 2 Rate Order process, in order to support rates being implemented as soon as possible. Appropriate evidence would be provided as part of the rate order process.

i. There may be additional adjustments included in certain future rate adjustment applications. For example, changes arising from Phase 3 of the Rebasing Application will be implemented after a decision is issued in Phase 3. This may best be done in a rate adjustment case, at the beginning of a year. As another example, if the OEB approves changes to the Company's cost of capital parameters in the current generic proceeding[31] on the cost of capital, the impact of such changes may be requested for implementation in a rate adjustment proceeding.

b) In Phase 2 of the annual rate application, Enbridge Gas will file an application for any ICM funding request by October 15 in each year during the IR term as follows:

   i. For projects approved for 'advanced' incremental funding as part of an LTC application, Enbridge Gas will update the preliminary rate rider using updated ICM parameters and supporting evidence including an AMP (or AMP update/Addendum) in the annual rate application when the project is planned to be in service.
   ii. For projects not requiring an LTC application and ALE projects,[32] Enbridge Gas will file an ICM request with supporting evidence, including an AMP (or AMP update/Addendum) using the ICM

[31] EB-2024-0063.
[32] As discussed at Phase 2 Exhibit 1, Tab 17, Schedule 1.

parameters in the year the project is planned to be in service to support the request for incremental funding.

54. As soon as reasonably possible following the public release of annual audited financial statements, Enbridge Gas will file actual utility results, including the determination of any earnings sharing amount, and apply for the disposition of deferral and variance accounts that are to be disposed of annually. Enbridge Gas will request that rate adjustments associated with deferral account dispositions be implemented in the earliest possible QRAM following the OEB's decision.

55. Enbridge Gas will continue to adjust gas supply commodity and upstream transportation costs through the QRAM mechanism as approved by the OEB.

8. Customer Protection Measures

56. Except for a proposed modification for the calculation of results for the Meter Reading Performance Measurement (MRPM) metric,[33] Enbridge Gas proposes a continuation of its scorecard to measure and monitor performance during the IR term. The scorecard includes measures for customer focus, operational effectiveness, public policy responsiveness and financial performance. Further details of Enbridge Gas's performance measurement and scorecard are provided at Phase 2 Exhibit 1, Tab 7, Schedule 1. Enbridge Gas will continue to produce the scorecard annually for review as part of the Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding.

[33] Enbridge Gas is proposing that all meters with access issues that are beyond the control of Enbridge Gas be excluded from the MRPM calculation for the purposes of the scorecard measure. Please see Phase 2 Exhibit 1, Tab 7, Schedule 1.

9. Deferral and Variance Accounts

57. Enbridge Gas will maintain deferral and variance accounts in accordance with the terms approved by the OEB as part of the Phase 1 Settlement Agreement.[34] The Company is also requesting approval to establish three additional deferral and variance accounts as part of Phase 2 Exhibit 9, Tab 1, Schedule 3: the Energy Transition Technology Fund Variance Account, a new OEB Cost Assessment Variance Account, and an OEB Directive Deferral Account. As part of Phase 3 of this proceeding, Enbridge Gas is also anticipating that additional new deferral and variance accounts will be requested, to commence during the IR term, along with the discontinuance of certain existing accounts approved as part of Phase 1 of the proceeding (for example new gas cost related accounts which would replace rate-zone specific accounts). To the extent that it is appropriate, the Company may request approval for deferral and variance accounts in the context of other proceedings before the OEB during the course of the IR term.

10. Considerations for Next Rebasing/IR Term

58. Enbridge Gas acknowledges that there will be a lot of change in the coming years, as government and regulatory policy relevant to energy transition and energy regulation evolves. The Company will turn its focus to its next IRM after Phase 3 of this proceeding is complete. Enbridge Gas plans to consult with interested stakeholders about the next IRM. This will help to get the benefit of a wide range of viewpoints and ideas.

59. While it is too early to have any overall expectation of what could be in the next IRM, one item that Enbridge Gas may consider is an Efficiency Carry-over

[34] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, Section I, pp. 53-58.

Mechanism (ECM). An ECM would take account of the fact that finding new efficiencies is becoming increasingly difficult for Enbridge Gas, with integration of the two utilities having now been completed. In many cases, further efficiencies require investments in new technology to reduce operating costs. The benefit for the Company and customers can be mis-matched for such investments, particularly late in an IR term. Enbridge Gas proposes therefore to consult with stakeholders to discuss whether and how an ECM could be created to allow Enbridge Gas to carry over some of the benefits from efficiency investments into the next IR term, such that the benefits are not all credited immediately to customers. The theory is that an ECM will incent Enbridge Gas to pursue efficiency initiatives in the later years of an IR plan and allow the Company to retain some of the efficiency gains or savings after rebasing, thus eliminating any disincentives for the Company to invest in efficiency-related investments during the later years of an IR plan.

TOTAL FACTOR PRODUCTIVITY, BENCHMARKING, AND RECOMMENDED INFLATION AND X FACTORS FOR ENBRIDGE GAS INC. INCENTIVE RATE-SETTING MECHANISM

BV PROJECT NO. 409074

PREPARED FOR

Enbridge Gas Inc.

15 MARCH 2024

BLACK & VEATCH

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1.0 Introduction and Summary

Enbridge Gas Inc. ("EGI," or "the Company") will propose an incentive rate-setting mechanism ("IRM") for the 2024-2028 term based on the Price Cap Incentive Rate-setting mechanism ("Price Cap IR") for its regulated gas utility operations. Under the Price Cap IR, rates are set through a cost of service process for the first year (2024) and then adjusted in years two to five (2025-2028) using a Price Cap Index ("PCI"), where base rates are adjusted by an "inflation minus X factor" formula.

EGI retained Black & Veatch Management Consulting ("BV") to undertake TFP and benchmarking research to support the Company's IRM proposal. Dr. Lawrence Kaufmann oversaw and managed this work on behalf of BV. BV's original TFP and benchmarking report was completed in October 2022, which was filed in the Rebasing application. Subsequently, the matter was moved to Phase 2.

BV has now reconsidered its analysis and what follows is an updated version of the study. This report updates the results presented in BV's previous report by adding 2022 data, and updating some 2021 data to the database used to develop TFP and benchmarking results.[1] In addition, BV has provided additional evidence that is germane to our recommendations. This evidence includes: 1) the most recently updated stretch factors for Ontario's electricity distributors; 2) the use and implications of the "k-bar" mechanisms recently included in performance-based regulation plans approved in Alberta and Massachusetts; 3) previous analyses of the EGI company's performance under incentive regulation; and 4) the implications of EGI's cost savings that will be rebased in 2024 rates. BV has also considered the OEB findings in the Phase 1 decision, and we do not believe the Phase 1 findings impact BV's recommended inflation factor, benchmarking analyses, or TFP estimates for the industry or EGI.

Drawing on this updated research, Dr. Kaufmann recommends an overall X factor to be used in EGI's proposed incentive rate-setting mechanism.[2] This report presents the updated results of the TFP and benchmarking studies developed for EGI as well as the following recommendations:

Inflation Factor: The recommended inflation factor in EGI's IRM is a weighted average of growth in the Canadian GDP Implicit Price Index for Final Domestic Demand ("GDP-IPI-FDD") and the Ontario Average Hourly Earnings ("AHE") indexes. This is an example of an "industry-specific" inflation factor, which is designed to track industry input price trends more closely than economy-wide price inflation. A 75% weight is proposed for the GDP-IPI-FDD and a 25% weight is proposed for the AHE. These weights are broadly consistent with the share of non-labor and labor costs for EGI and other gas distributors. They are also similar to recent inflation factor precedents in Ontario.

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[1] At the time the 2022 report was prepared, there were a number of missing 2021 values in the S&P database for some companies. Rather than eliminate those companies from the sample because of a single year's lack of data, B&V chose to use data values from the previous year (*i.e.* the most recent, available data) as the best available 2021 data. In 2022, actual data on these missing data points were available and substituted for the missing 2021 values. S&P also updated other 2021 values in the 2022 database, and those more recent data were also integrated into the updated study.

[2] The updated study also made one minor methodological change to the calculation of costs. In the previous study, distributors' capital additions were equal to the sum of gas distribution capital additions plus general gas plant additions. In the update, general gas plant additions were apportioned between distribution and non-distribution gas operations by multiplying general gas plant additions by the ratio of (gross gas distribution plant/total gas plant) in each year, for each company. This modification changed the estimated industry TFP trend by only one basis point.

Productivity Offset: In IRM plans with industry-specific inflation factors, the "productivity offset" component of the X factor should be equal to the long-run TFP trend for the respective utility industry. Because necessary data on Canadian gas distributors outside Ontario are not readily available, this study uses data on the United States ("U.S.") gas distribution industry to estimate industry TFP trends. Our study estimates a long-run TFP trend for U.S. gas distributors of -1.52 % per annum. This value is in line with productivity offsets proposed by, and approved for, U.S. gas distributors in recent regulatory proceedings.

Stretch Factor: The recommended stretch factor is zero. This recommendation is supported by cost benchmarking studies and other evidence that show EGI is a very good cost performer and therefore has less potential to achieve incremental efficiency gains than most of the rest of the industry. In particular, BV's analysis shows:

- The Company's cost performance ranked number five among the 55 gas distributors sampled in BV's cost benchmarking study (*i.e.* the 54 sampled U.S. gas distributors plus EGI); this is consistent with top decile cost performance.
- Over the 2020-2022 period, EGI's average unit cost (*i.e.* total gas distribution costs per customer) was:
  - 47.6% below the average unit cost of gas distributors in the Northeast U.S.
  - 30.6%% below average unit costs of the entire U.S. gas distribution industry
  - 29.1% below the average unit cost of seven, selected gas distribution peers.
- The Company's gas distribution operations and maintenance ("O&M") expenditures per customer were the lowest in Canada and 78% below the average O&M costs per customer for a sample of eight other Canadian gas distributors.

While all the benchmarking evidence supports the view that EGI is a top cost performer, BV believes the Northeast U.S. aggregate is EGI's most relevant comparator. This region operates under a business and regulatory/policy environment more similar to Ontario's than much of the rest of the U.S. gas distribution industry.

In addition to the benchmarking evidence, it is important to recognize that EGI customers will benefit from $188.7 million of productivity, operational settlement cost reductions that are flowed through to 2024 rates. This is the first year of the new IRM plan, and customers will receive rate reduction of approximately 2.6% in that year as cost savings are rebased into 2024 rates. These costs savings reflect ongoing integration efficiencies that have been made possible by the amalgamation, as well as the Company's continuous, aggressive pursuit of productivity gains.

These rebased cost savings have direct implications for the stretch factor. Customers benefit from the new IRM plan immediately, because productivity and integration savings are reflected in lower rates from the outset of the new plan. Since rebased cost savings generate immediate customer benefits, there is less need to rely on the stretch factor to ensure that customers will benefit under the Company's new IRM proposal.

Even more importantly, passing cost savings onto customers in rebased rates will typically create more benefits for customers than passing an equivalent magnitude of benefits to customers through the stretch factor. The reason is simply that rebased cost savings benefit customers in year one of the plan. In contrast, customers must wait for the stretch factor to distribute benefits, since this does not occur until the revenue adjustment mechanism takes effect in year two of the plan.

In addition, it is important to realize that lower rebased rates will benefit customers beyond the first plan year. In year two of a PBR plan, revenue adjustment mechanisms are applied to revenues from the preceding, “cast-off” year. The amount of additional revenue generated by the IRM adjustment will naturally be smaller for smaller values of cast-off revenues. Therefore, when rebased cost savings reduce cast-off revenues, they simultaneously reduce the amount of additional revenue resulting from IRM revenue adjustment formulas in year two and, in fact, every other succeeding year of the IRM plan.

Passing cost savings into rebased cast-off rates therefore has ripple effects that reduce rate changes in each year of an IRM plan. This is analogous to how the stretch factor reduces revenues in each plan year. However, rebased cost savings reduce revenue changes by reducing the revenue base to which PBR adjustment formulas are applied, while the stretch factor reduces the rate of change of adjustment formulas directly.

Because rebased cost savings reduce revenues in year one of the PBR plan and each successive year, while the stretch factor leads to only four years of customer benefit, rebasing cost savings is likely to create greater benefits for customers than a stretch factor of equal magnitude.

Finally, recent stretch factor precedents for Ontario’s electricity distributors support a zero stretch factor for EGI. For about a decade, stretch factors for Ontario electricity distributors have been updated based on their measured cost performance in the industry. Distributors with top cohort performance are assigned a stretch factor of zero.

In the most recent, 2023 stretch factor update, 30% of Ontario’s electricity distributors were assigned a stretch factor of zero.[3] Approximately the “top third” of cost performers in the electricity distribution industry are therefore currently assigned zero stretch factors. This is nearly a quadrupling of the 8.2% of electricity distributors assigned zero stretch factors at the outset of the stretch factor update regime. This is compelling evidence that the OEB’s consistent, ongoing application of incentive regulation in Ontario’s electricity distribution industry since 2008 has created strong performance incentives that led to cost performance gains.

Enbridge Gas Distribution, Union Gas, and the amalgamated EGI have also been subject to ongoing, comprehensive incentive regulation from 2008 to the present. The benchmarking evidence strongly supports the view that the Company has achieved similar cost performance gains over the same period. In addition, the Company’s “top decile” performance in its industry is superior to the “top third” performance standard currently associated with zero stretch factors for Ontario’s electricity distributors.

In BV’s opinion, EGI’s performance levels are commensurate with the thresholds the OEB uses to assign zero stretch factors to the “top cohort” of electricity distributors. EGI’s exceptional benchmarking results, as well as the sizeable customer benefits resulting from cost savings flowed

[3] “Empirical Research in Support of Incentive Rate-Setting: 2022 Benchmarking Update, Report to the Ontario Energy Board, Pacific Economics Group, July 2023

through to 2024 rates, also support a zero stretch factor. For all these reasons, as well as other relevant evidence, BV recommends a stretch factor of zero for EGI's IRM proposal.

Overall X Factor: Given a recommended productivity offset of -1.52% and a recommended stretch factor of zero, an overall X factor of -1.52 % is recommended for EGI's IRM plan.

The report is organized as follows. After this brief introduction and summary, Section 2 addresses the framework that underpins the development of Incentive rate-setting mechanisms and the relationship between industry TFP growth and the value of the X factor in rate adjustment mechanisms. Section 3 discusses the inflation factor. Section 4 describes the methodology used to estimate TFP and input price trends and presents TFP trends for the U.S. gas distribution industry, as well as recent historical TFP trends for EGI. Section 5 presents cost benchmarking data that compares EGI's recent cost performance to the U.S. national and regional gas distribution industries, as well as selected U.S. and Canadian gas distribution peers. Drawing on this TFP and cost benchmarking evidence, Section 6 provides recommendations on both the productivity offset and stretch factor components of EGI's proposed X factor, as well as a recommendation on the inflation factor. Section 7 provides additional details of this work in a Technical Appendix.

2.0 Some Principles for Setting X Factors

Rate and revenue indexing mechanisms are widely used in utility regulation. Indeed, Ontario has extensive experience with this regulatory approach, and the Ontario Energy Board ("OEB") has approved numerous indexing plans for gas and power utilities over the last 20-plus years. Many interested parties in Ontario are therefore familiar with the rationale for "inflation minus X" mechanisms, but a brief review of this conceptual framework may nevertheless be helpful.

The North American approach to rate and revenue indexing is grounded in economic reason.[4] The basic principle is that regulation should simulate competitive market outcomes where competition itself is impractical. This principle is sometimes called the competitive market paradigm.

This paradigm can be made operational through the use of economic indexes. Because competitive industries earn a competitive rate of return in the long run, an index of a competitive industry's product prices (*i.e.* the industry output price index) will grow at the same rate as an index of the industry's unit costs (*i.e.* industry cost per unit of output) over the long run. This relationship is presented in equation [2.1] below.

$$trend\ Output\ Prices^{Industry} = trend\ Unit\ Cost^{Industry}. \qquad [2.1]$$

It is important to recognize that, under competitive market conditions, output price changes reflect *industry* conditions, not the unit cost experience of any individual firm. Because industry prices are not sensitive to individual suppliers' cost changes, individual firms keep all the after-tax benefits from efforts to slow unit cost growth. Each firm therefore has strong incentives to keep the growth in its unit cost below the industry-average unit cost trend, which in turn determines long-run price changes for the industry.

A further result of indexing logic is useful for setting the terms of rate and revenue indexing mechanisms. The trend in an industry's unit cost can be shown to be equal to the difference between the trends in its input price and TFP indexes, or

$$trend\ Unit\ Cost^{Industry} = trend\ Input\ Prices^{Industry} - trend\ TFP^{Industry}. \qquad [2.2]$$

TFP is equal to industry output quantity divided by industry input quantity, so the trend in the industry TFP index is equal to the growth in industry output quantity minus the growth in industry input quantity. Equation [2.2] provides an alternative but equally accurate way to understand TFP growth: as the difference between industry input price and unit cost trends. TFP trends capture all the factors that lead an industry's unit cost to grow at a different rate than the trend in industry input prices.

[4] The U.K. also has a long history with "inflation – X" adjustment mechanisms, but its experience and conceptual rationale for calibrating such mechanisms differs from the standard North American approach. Although the U.K. approach has evolved over time, its basic "I – X" framework is more similar to what in Ontario is termed "Custom IR," or forward-looking, company-specific, cost-based plans.

A PCI in an IRM can be designed to track the industry unit cost trend by conforming to the following formula.

$$\begin{aligned} trend\ PCI &= trend\ Input\ Prices^{Industry} - trend\ TFP^{Industry} \\ &= trend\ Input\ Prices^{Industry} - X \\ X &= trend\ TFP^{Industry} \end{aligned} \quad . \qquad [2.3]$$

Equation [2.3] shows that the growth in the PCI has two terms: 1) an inflation factor that reflects industry input price trends; minus 2) an X factor, which reflects the industry's long-run TFP trend. The competitive market paradigm therefore establishes a direct connection between the inflation factor in an IRM and the trend in industry input prices, and the X factor in an IRM and industry TFP trends. The following section addresses the choice of the inflation factor in more detail.

3.0 Inflation Factor

3.1 Industry-Specific and Economy-Wide Inflation Factors

As discussed, there is a direct conceptual link between the inflation factor in a PCI mechanism and measured input prices in the utility industry. In practice, two main types of inflation factors are used in rate or revenue adjustment mechanisms. One is an industry-specific inflation factor designed to reflect input price trends in the utility industry. The second is a broad, economy-wide measure of output price inflation.

An industry-specific inflation factor is constructed as a weighted average of inflation in two or more price "sub-indices." Sub-indices are chosen to reflect price changes for different sets of inputs used in production, such as labour prices.[5] In contrast, an economy-wide inflation factor measures input prices using only a single index of output price inflation in the macro-economy.

Of the two options, the industry-specific inflation factor is clearly more compatible with the competitive market paradigm and associated indexing logic. Relatedly, industry-specific inflation factors should provide a more accurate measure of the industry's actual input price changes than an economy-wide inflation factor.

The main disadvantage of industry-specific inflation factors is they are more complex to implement. For example, constructing industry-specific inflation factors requires choices on the number of input classes included in the factor; specific sub-indices to measure prices for each respective set of inputs; and estimates of the share of each selected input class in total industry cost, to use as weights on the sub-indices.

In contrast, economy-wide inflation factors are simple and straightforward to use. Economy-wide inflation factors use "off the shelf" inflation indices developed by government authorities. There is accordingly no need to construct the inflation factor using disparate sources of information.

There are two main disadvantages with economy-wide inflation factors. The first is they are less likely to track the actual growth in input prices for the utility industry. The second is an economy-wide inflation measure can complicate the calculation of the X factor.

This latter disadvantage can be demonstrated by returning to the indexing logic developed in Section 2. Recall that this logic established a direct link between the X factor and industry TFP trends. However, when a plan uses an economy-wide inflation factor, the X factor in the IRM is often calculated using more than industry TFP trends. The X factors in IRM plans with economy-wide inflation factors often begin with estimates of industry TFP growth but also include other adjustments to help the indexing mechanism better reflect industry unit cost trends.

Consider the common example of indexing plans that use the U.S. gross domestic product price index (GDPPI) as an inflation factor. To examine the impact of this selected inflation factor on the indexing logic, we can simply add and subtract the growth in GDPPI from the right-hand side of equation [2.2]

[5] In practice, it is common for a broad-based, economy-wide inflation measure to be one of the selected subindices used to construct an industry-specific inflation factor. Nevertheless, an inflation factor that includes direct measures of the price of industry inputs (such as labour) enables the inflation factor to track industry input price inflation more accurately than relying entirely on an economy-wide macroeconomic price index.

(previously presented in Section 2 of this report), since adding and subtracting the same term from one side of an equation leaves that equation unchanged.

$$\begin{aligned} trend\ Unit\ Cost^{Industry} &= trend\ GDPPI - trend\ TFP^{Industry} \\ &\quad + \left(trend\ Input\ Prices^{Industry} - trend\ GDPPI\right). \end{aligned} \qquad [3.1]$$

Next, because the aggregate U.S. economy is broadly competitive, we can apply the same indexing logic to the U.S. economy that was previously undertaken for the utility industry. This logic implies that the trend in GDPPI (*i.e.* an output price index for the entire U.S. economy) can be expressed as the difference between the trends in input price and TFP indexes for the overall U.S. economy.

$$trend\ GDPPI = trend\ Input\ Prices^{Economy} - trend\ TFP^{Economy} \qquad [3.2]$$

Substituting equation [3.2] into equation [3.1] and simplifying yields the following:

$$\begin{aligned} trend\ Unit\ Cost^{Industry} &= trend\ GDPPI \\ &\quad - \begin{bmatrix} \left(trend\ TFP^{Industry} - trend\ TFP^{Economy}\right) \\ + \left(trend\ Input\ Prices^{Economy} - trend\ Input\ Prices^{Industry}\right) \end{bmatrix} \end{aligned}$$

The equation above is similar to equation [2.3] in that the trend in industry unit cost is decomposed into two factors: the GDPPI as the inflation factor, and the term in brackets as the X factor. However, this X factor is not equal to the industry TFP trend, as it is when an industry-specific inflation factor is used to measure industry input price trends. Instead, the X factor is now equal to the sum of two other terms: 1) a productivity differential, equal to the difference between the TFP trends of the industry and the overall economy, and 2) an inflation differential, equal to the difference between the input price trends of the economy and the industry.

It should be noted that this X factor is not simply a theoretical implication of the indexing logic when economy-wide inflation factors are used in IRMs. This more complex X factor formula has in fact been implemented in many Performance-Based Regulation ("PBR") plans. For example, the Massachusetts Department of Public Utilities has used the sum of the productivity differential and inflation differential to calculate X factors in at least eight approved indexing plans. This same formula has also been applied in New Zealand and Australia and was recently proposed for a PBR plan in Hawaii.

3.2 Inflation Factor Precedents in Ontario

The OEB has approved both economy-wide and industry-specific inflation factors in incentive regulation plans for energy utilities. The current IRM for EGI uses an economy-wide inflation factor (*i.e.* the GDP-IPI-FDD). Most of the other approved IRM plans for Ontario gas distributors have also used economy-wide inflation factors.

However, there is also precedent for the use of industry-specific inflation factors in Ontario. Most prominently, in Fourth Generation incentive ratemaking for electricity distribution and transmission utilities ("4thGenIR"), the OEB indicated that "it wanted to adopt a more Ontario industry-specific inflation factor than the Canadian economy-wide index used in 3rd Generation IR."[6] The OEB further

[6] *Report of the Board*, EB 2010-0379, November 13, 2013, p. 5.

stated that the development of an appropriate industry-specific inflation factor in 4thGenIR should be constructed and updated using data that are readily available from public and objective sources.

The OEB ultimately approved a two-factor industry-specific inflation factor in 4thGenIR. This inflation factor was a weighted average of inflation in: 1) a labour sub-index measured by the average weekly earnings ("AWE") for workers in Ontario; and 2) a non-labour sub-index measured by the Canadian GDP-IPI-FDD. The OEB considered but rejected a three-factor inflation factor that also included a capital cost subindex (computed as part of the TFP study for OEB Staff) because this sub-index was too volatile. The OEB also noted that the Alberta Utilities Commission had recently implemented a two-factor inflation factor in Alberta that used analogous non-labour and labour price indices (*i.e.* the Canadian GDP-IPI-FDD and Alberta AWE).

The OEB's approved inflation factor applied a 30% weight to the AWE index and a 70% weight to the GDP-IPI-FDD. These weights were based on the estimated labor/non-labor cost split for medium and large electricity distributors in Ontario.[7] The OEB noted that the cost share estimates that were adopted may now be outdated, but there were insufficient data to refine or update the estimate.

In EB-2021-0212, the OEB initiated a generic proceeding to review the 2022 inflation factors to be used in the electricity distribution IRM plans. This review was prompted by Covid-related impacts on measured input prices. The OEB found that the 4thGenIR methodology for developing inflation factors remained appropriate for 2022. This relatively recent precedent (from November 18, 2021) is therefore consistent with the continued use of a two-factor inflation factor. While the OEB has previously approved the use of the AWE to construct a two-factor inflation factor in IRMs, a strong case can be made that average hourly earnings ("AHE") is a better measure of price inflation for labour inputs. The AWE measures average wages paid in a week, which involves the product of average hourly wages and average hours worked per week. Because average hours worked is a measure of labour input *quantity*, the AWE is the product of input quantity and input price data. In contrast, the AHE measures the price of labour inputs directly and exclusively.

The indexing logic presented in Section 2 shows that input quantities and input prices are reflected in different components of the PCI formula: input quantities (including the quantity of labour inputs) are captured in measures of industry TFP trends; input prices are captured in the inflation factor. Neither the industry input price or TFP components of the PCI are measured by the direct product of input price and input quantity data.

Because the AWE is a product of input price and input quantity data while the AHE is a direct measure of input prices, the AHE is more compatible with the underlying indexing logic than the AWE. BV therefore recommends that the Company's inflation factor be computed as a weighted average of the GDP-IPI-FDD and the AHE. BV further recommends weights of 25% and 75% be applied to the AHE and GDP-IPI-FDD respectively. The recommended 25% weight on labour prices is a bit lower than the 30% share approved in 4thGenIR, but a 25% share is more strongly supported by BV's empirical work and estimated labor cost shares for both EGI and the U.S. gas distribution industry.

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[7] The estimated 30% cost share for labor assumed that 70% of operations and maintenance ("O&M") costs were associated with labor inputs. This assumption was initially used in the First Generation IRM plans implemented in Ontario in the late 1990s.

4.0 TFP Estimates

The productivity offset component of the X factor is developed using estimates of industry TFP trends. BV estimated the growth in industry TFP and related indices on behalf of EGI. This section discusses the TFP research and results.

4.1 Data Sources and Sample Period

The main data source for the TFP study was provided by S&P Global Market Intelligence. The S&P database compiled most of the cost and output data necessary to estimate TFP trends. BV personnel compiled historical data on several price indices, which were used to deflate changes in input costs and thereby express changes in inputs in "real," quantity terms. These input price indices are described further in Section 4.4.

There were sufficient data from S&P to estimate TFP trends for 54 U.S. gas distributors.[8] This sample includes a diverse array of small, medium and large gas distributors throughout all regions of the country. Notably, 19 of the 54 distributors were located in the Northeast U.S., which is adjacent to most of EGI's customers and distribution service territory. A sixteen-year sample period was used to estimate TFP trends, from 2006 through 2022.

4.2 Applicable Total Cost Measures

Two measures of total costs were developed for EGI: one covering the costs of all the Company's regulated distribution, transmission, and storage operations; the second covering only the Company's regulated distribution operations. In both instances, total costs were computed as the sum of labour costs, non-labour O&M costs, and capital costs for the designated set of EGI operations.

The broader cost measure was developed because the IRM proposal applies to all of the Company's regulated distribution, transmission and storage services. Although the X factor for this IRM is based on industry TFP trends rather than the Company's own TFP growth, TFP growth for Company services subject to the IRM is potentially informative to the OEB and other interested parties.

EGI's distribution cost measure was computed to facilitate "apples to apples" comparisons between EGI and U.S. gas distributors. Most sampled U.S. distributors had negligible (or zero) transmission and storage assets, so BV computed total costs for the gas distribution operations only of sampled distributors. It was therefore necessary to compute measures of EGI's distribution-only costs to enable appropriate benchmarking comparisons between EGI and the U.S. gas distribution industry.

4.3 Output Quantity Index

Output quantity was measured by the total number of customers served. This is the standard output measure in gas distribution TFP studies given the long-term trend of declining gas consumption volumes per customer. These trends have accelerated in recent years because of "energy transition" policies designed to reduce reliance on carbon-based energy sources, including natural gas. As a result, revenue decoupling and related mechanisms have become more prominent throughout the industry. These

[8] One sampled gas distributor is Colonial Gas in Massachusetts, which filed annual reports through 2020, but was fully absorbed into Boston Gas's operations in 2021. Colonial Gas accordingly did not file independent reports in 2021 or 2022. The BV team used independently-reported data from Colonial Gas as much as possible, but combined Colonial Gas with Boston Gas in 2021 and 2022 to compute cost and input data.

mechanisms encourage distributors to reduce natural gas sales by compensating them for lost gas distribution margins when sales decline.[9]

Because of these trends and policy efforts, it is inappropriate to include gas volumes in the output quantity index. Doing so would lead to much slower growth in measured distribution output. This would, in turn, greatly reduce measured TFP growth, particularly since few, if any, gas distribution costs are driven entirely by volumes. It is also not practical to include peak demand as an output measure, because high-quality data on distributors' peak demands are not widely available. Given the data constraints, long-term gas consumption trends, and current policy direction, the most appropriate measure of gas distribution output is the number of customers served.

4.4 Input Quantity and Input Price Indexes

Inputs were categorized into three categories: labour, capital, and non-labour O&M inputs. Labour quantity was equal to annual labor costs divided by an employment cost index. The selected employment cost index for sampled U.S. utilities was the Employment Cost Index for private industry utility workers ("ECI"), computed by the U.S. Bureau of Labor Statistics ("BLS"); the employment cost index for EGI was Ontario Average Hourly Earnings ("AHE").

The quantity of non-labour O&M for U.S. distributors was computed by dividing total O&M costs, net of labour costs, by the U.S. GDPPI. The quantity of EGI's non-labour O&M was calculated by dividing EGI's analogous cost measure by the Canadian GDP-IPI-FDD. Capital quantity was computed using a perpetual inventory equation and a hyperbolic decay method of asset depreciation. Details on the measurement of capital quantity and costs are presented in Section 7's Technical Appendix. A Tornqvist index was used to aggregate the three inputs into an overall index of input quantity.

4.5 TFP Growth

TFP growth was measured directly as the growth in customers minus the growth in overall input quantity.

4.6 Empirical Results

Table 1 summarizes the main results of this indexing research. Data are presented on the growth in output, input quantity and TFP over the 2006-2022 period for the U.S. sample, EGI's total regulated services, and EGI's distribution services. In addition, data are presented on the average annual growth in labour, non-labour, and capital inputs over the 2006-2022 period for the U.S. sample, EGI's total regulated operations, and EGI's distribution operations.

Table 1: Summary of Results, 2006-2022

	% Change Output	% Change Input	% Change TFP	%Change Labor	%Change Non-labor O&M	%Change Capital
U.S. Sample	0.68%	2.20%	-1.52%	0.91%	0.97%	3.25%
EGI All Regulated Services	1.45%	1.59%	-0.14%	-1.15%	0.95%	3.34%

[9] EGI does not operate under full revenue decoupling, but it does have an average-use adjustment that encourages less use of natural gas by providing some compensation when gas usage declines.

EGI Distribution	1.45%	1.81%	-0.36%	-1.01%	1.25%	3.22%

For the U.S. sample, it can be seen that output (*i.e.* customer numbers) grew by an average of 0.68% per annum, while overall input grew at an average annual rate of 2.20. As a result, industry TFP declined at an annual rate of 1.52% over the 2006-2022 period. (*i.e.* the average change in TFP for the U.S. gas distribution industry was -1.52% per annum).

Further examination of the input quantity subindices shows that the growth in inputs was driven by greater capital spending. Capital inputs grew at an average annual rate of 3.25% over the sample period. In contrast, labour and non-labor O&M inputs grew at average annual rates of 0.91% and 0.97%, respectively. In both cases, this was less than half the growth rate of capital.

Negative TFP growth for the U.S. gas distribution industry is therefore the result of slowing output growth coupled with simultaneously rapid capital spending. These empirical results are consistent with generally recognized trends in the industry, including slow output growth and the need to replace aged gas distribution infrastructure for safety, reliability and policy-related reasons. All of these trends are particularly pronounced in the Northeast U.S.

BV's estimate of negative TFP trends in the gas distribution industry is also broadly supported by other evidence recently provided in Ontario. In EGI's MAADs proceeding (EB-2017-0306/EB-2017-0307) that approved the current IRM, Pacific Economics Group Research ("PEG") prepared a U.S. gas distribution TFP study on behalf of OEB staff.[10] Table 6-revised in PEG's report presents estimated trends in gas distribution output quantity, input quantity, and TFP, as well as the trends in capital and O&M input quantities, for a sample period ending in 2016.

Table 2 summarizes PEG's main results for the most recent 15 years of its sample period. The table presents results for the entire 15-year period, as well as the approximate "First Half" and "Second Half" results of the full sample period (*i.e.* the first eight years of the period from 2001-2009, and the last seven years of the period from 2009-2016, respectively).

Table 2: Summary of PEG's TFP Results, 2001-2016 (EB-2017-0306/EB-2017-0307)

	% Change Output	% Change Input	% Change TFP	%Change Labor	%Change O&M	%Change Capital
All 15 Years	0.83%	1.38%	-0.55%	NA	0.19%	1.88%
First Half of sample, 2001-2009	1.01%	0.99%	-0.2%	NA	0.60%	1.32%
Second Half of sample, 2009-2016	0.68%	1.72%	-1.04%	NA	-0.18%	2.36%

Over the entire 2001-2016 period, PEG estimated that industry TFP declined by 0.55% per annum (*i.e.* average annual TFP growth of -0.55%). Output grew by 0.83% per annum, while industry input quantity grew by 1.38% per annum. Capital inputs grew by 1.88% per annum between 2001-2016, which was far above the 0.19% average growth in O&M inputs over the same period.

PEG's results also indicate that the industry's negative TFP trend is accelerating over time. In 2001-2009, TFP declined by 0.02% per annum. In 2009-2016, the TFP decline accelerated to 1.04% per annum.

[10] Lowry, M.N. (2018), "Exhibit M1, IRM Framework for the Proposed Merger of Enbridge and Union Gas, May 4 2018. "

Approximately 32% of PEG's estimated, accelerated TFP decline was due to slowing output growth.[11] Less rapid growth in O&M inputs in 2009-2016 offset the lower TFP growth in the second half of the sample. The lion's share of the accelerated TFP decline (more than two thirds) was therefore due to more rapid growth in capital inputs in 2009-2016 compared with 2001-2009.

Similar to BV's results, PEG's 2018 study provides strong evidence of negative TFP trends in the natural gas distribution industry through 2016. PEG's estimates also show that the rate of TFP decline has been accelerating over time, primarily because of increased capital spending. If PEG's estimated "second half" TFP experience continued beyond 2016, and through the 2016-2022 period, it would naturally lead to an even lower estimate of the industry's long-term TFP trend.[12]

Turning to the EGI results, it can be seen that the Company's output has grown at an average annual rate of 1.45% over the 2006-2022 period. This is about double the output trend of the U.S. industry, but much of the Company's rapid output expansion occurred in the early years of the sample. For example, in the first two sample years (2006-2007), EGI's customer growth grew at an average annual rate of 2.19%. In the last two sample years (2021-2022), EGI's output growth decelerated to 1.0% per annum which is more consistent with (but still above) the slower, long-term output trend of the U.S. industry.

Input quantity for all of EGI's regulated transmission, distribution and storage services has grown at an average rate of 1.59%, which is somewhat below the 2.18% input growth trend of the U.S. industry. The main reason EGI's input quantity has grown more slowly than the industry average is due to labour inputs. Following the amalgamation of Enbridge Gas Distribution and Union Gas, the Company made significant reductions in labor expenses in 2019-2020. EGI's declines in labour costs have not been replicated industry-wide, although labour inputs have grown more slowly than either non-labour O&M or capital inputs for both EGI and the entire industry.

Importantly, EGI and the industry as a whole exhibit similar capital input trends. For the last 16 years, capital input has grown by more than 3% per annum for EGI's total operations, EGI's distribution operations, and the overall industry. This is evidence of long-standing capital spending pressures throughout the industry. EGI's capital input growth (3.34% for all operations and 3.22% for distribution operations) has closely tracked the industry's overall trend of 3.25% per annum.

It is also instructive to compare EGI's TFP trends for all regulated services and distribution services. Output growth is the same for both, but inputs have grown a bit more rapidly for distribution (1.81% per annum versus 1.59% per annum for all regulated services). For both sets of EGI services, however, TFP growth has been negative over the 2006-2022 period.

EGI's TFP decline has been less rapid than the U.S. industry's for two main reasons: 1) EGI's more rapid output growth; and 2) the labor cost savings achieved during the amalgamation. In recent years, however, the Company's output trend has become more similar to the U.S. industry's long-run trend. It is also unlikely that the Company will achieve a similar magnitude of merger-related savings in the near future.

[11] TFP growth declined from -0.02% to -1.04%, or 102 basis points, between the first and second halves of the sample. Output growth declined from 0.1.01% to 0.68%, or 33 basis points, between the first and second halves of the sample, and 33/104 = 0.323.

[12] For example, if PEG's estimated TFP trend of -1.04% for the 2009-16 period continued in each year between 2017 and 2022, it would yield a 16-year, 2006-2022 TFP trend of -1.08% per annum.

5.0 Cost Benchmarking

5.1 Industry Benchmarking

Data used in the TFP study was also used to benchmark EGI against the U.S. gas distribution industry. This benchmarking study examines EGI's unit cost (UC) of production for gas distribution against the U.S. industry. Unit cost is equal to the total cost of production divided by output, as measured by customer numbers. Unit costs are therefore equal to total gas distribution costs per customer.

Unit cost levels were computed annually for the 2020-2022 period. The Company's average UC over this period were then compared to analogous UC measures for three different U.S. sample aggregates: 1) the overall U.S. sample of 54 gas distributors; 2) the sample of 19 gas distributors in the Northeast U.S.; and 3) a sample of seven U.S. utilities that were selected as peers of the Company. The selection of peers is discussed below.

5.2 Selection of Peers

Utility benchmarking studies often compare a company to selected "peer" utilities that operate under similar business conditions. Two salient business conditions should be considered when identifying peers for EGI. The first is that EGI is one of the largest gas distributors in North America, serving approximately 3.8 million distribution customers. Larger utilities often benefit from economies of scale that reduce the unit cost of operations.

In addition, the EGD and Union South rate zones serve relatively dense service territories, which include the central business district and metropolitan area of one of North America's largest cities (Toronto). While a certain amount of customer density can reduce the unit cost of gas distribution (*e.g.* by allowing more customers to be served by a single distribution main), "extreme" density levels often create challenges that raise gas distribution costs. The Union North rate zone serves a smaller and much less dense service territory, but it accounts for only about 10% of EGI's overall customers.

Given these operating circumstances, it is reasonable for EGI to be compared against peer utilities that serve a similarly large number of customers, operate within a relatively dense service territory, or both. Our analysis therefore compares EGI to sampled U.S. gas distributors that serve large and/or densely populated territories. Table 3 shows the five largest U.S. gas distributors in the industry sample in terms of 2021 customers served, as well as EGI.[13]

Table 3: Gas Distributors Ranked by Size

Company	Average customers served, 2019-2021
1. Southern California Gas	5,907,112
2. Pacific Gas and Electric	4,533,299
3. EGI	3,756,588
4. Public Service Electric & Gas	1,857,011
5. Consumers Energy	1,795,038

[13] The size and density criteria established in the initial report were designed to identify a list of peers for EGI. The size criterion in the initial report used average customers served over the 2019-2021 period, and the density criterion used customers per mile of main for the 2018-2020 period. Updating these intervals for measuring size and density to include more recent data would not materially impact the data and, more importantly, would not change the selected peers. For simplicity, these intervals were therefore not adjusted.

6. Atlanta Gas Light	1,564,628

Table 4 shows the top five U.S. gas distributors ranked in terms of customers per mile of gas distribution main, a common measure of customer density, as well as EGI.

Table 4: Gas Distributors Ranked by Density

Company	Customers per mile of main, 2018-2020
1. Consolidated Edison	247.64
2. People's Gas Light and Coke	197.59
3. Southern California Gas	113.26
4. Pacific Gas and Electric	103.99
5. Public Service Electric and Gas	103.08
6. EGI	76.43

EGI's customer density is lower than the top five U.S. gas distributors, as ranked by customers per miles of distribution main. This is due to the lower customer density in the Company's Union North rate zone operations. If the EGD rate zone was treated as a stand-alone distributor, its customer density would be just below the density levels of the two most densely-populated U.S. gas distributors.

Most of EGI's customers, and customer costs, are associated with EGI's southern and not its northern operations. Most of the Company's costs are therefore associated with its densely-populated EGD and Union South rate zones operations, and only a small share are associated with the far less dense Union North rate zone operations. Since the benchmarking analysis compares cost per customer, BV therefore believes it is appropriate to compare EGI's overall costs per customer against the most densely populated U.S. gas distributors, even though EGI's overall customer density is somewhat lower due to the relatively small portion of its operations (in terms of cost) that serves a far less densely populated territory.

A total of seven gas distributors, other than EGI, appear on either the size or density rankings. Three companies appear on both: Southern California Gas, Pacific Gas and Electric, and Public Service Electric and Gas. The four other distributors are Consolidated Edison, People's Gas Light and Coke, Atlanta Gas Light, and Consumers Energy. EGI's unit costs were compared against these seven peer distributors.

5.3 U.S. Gas Distribution Benchmarking

EGI's unit costs (for distribution services) were computed and expressed in U.S. dollars using the average 2018-2020 purchasing power parity exchange rate of 0.84. Table 5 displays these results, averaged over the 2020-2022 period, for the U.S. sample, the Northeast U.S. sample, and the seven peers.

Table 5: U.S. Cost Benchmarking Comparisons 2020-2022 (U.S. $)

Aggregate/Peer	Unit Cost	Unit Cost Difference
EGI	$278.3	NA
U.S. Sample	$392.8	-29.1%
Northeast U.S.	$531.1	-47.6%
Peer Average	$400.9	-30.6%
Cons. Edison	$648.1	-57.1%
Peoples GL&C	$579.7	-52.0%

SoCalGas	$315.8	-11.9%
PG&E	$380.4	-26.9%
PSE&G	$342.1	-18.6%
Consumers Energy	$280.2	-0.7%
AGL	$259.7	7.1%

The "Unit Cost Difference" column computes the percentage difference between EGI's unit costs and the analogous unit costs for EGI comparators. In Table 5, these comparators are the U.S. industry aggregate, the Northeast U.S. industry aggregate, the peer average, and each of the seven peers individually. It can be seen that EGI's 2020-2022 average unit cost was 29.1% below average unit costs of the U.S. gas distribution industry and 47.6% below the average unit cost of the Northeast gas distribution industry. EGI's average unit cost is 30.6% below the average unit cost of its seven gas distribution peers, and its unit costs are below six of the seven selected peers.

In fact, only four of the 54 sampled U.S. gas distributors had lower unit costs than EGI. The Company's unit cost is therefore fifth lowest among the 55 sampled North American gas distributors. This is consistent with top decile performance within the gas distribution industry.

The Company's cost performance is even better when compared against the Northeast industry, which is a more relevant comparator for EGI than the national industry for at least three reasons. One is that gas distributors in the Northeast have a much larger share of cast iron and bare steel assets within their territory. This, in turn, results from the fact that gas distribution systems in the Northeast U.S. were developed earlier than in most of the U.S., simply because this region was settled earlier and therefore has more long-settled, "mature" large cities where the industry's initial infrastructure was installed.

These initial investments naturally used the materials for fabricating underground pipe that were available at the time. In the earliest days of the industry, pipes were made using cast iron, and in later years "bare" (*i.e.* unprotected) steel became the dominant material. It was not until well after WWII that the now-standard Polyethylene ("PE") pipe was used for most services and local distribution mains.

Because of this historical legacy, a significant number of Northeast U.S. utilities – as well as EGI – continued to have a substantial inventory of aged cast iron and/or bare steel assets until recent years. In contrast, cast iron and bare steel pipe was much less common in other regions.

EGI has now replaced nearly all its aged cast iron or bare steel assets. This is also true of some other U.S. distributors, and every other distributor facing the issue is in the process of doing so. Cast iron and bare steel asset replacement is expensive, particularly since many of these efforts necessarily take place in crowded urban areas and therefore require more time and expense than replacing assets in less densely populated areas. These replacement costs therefore raise the unit cost of gas distribution service in territories with such legacy assets. The concentration of cast iron and bare steel replacements in the Northeast U.S. is an important reason why the region's unit cost of $531 is more than 30% above the unit cost of the entire U.S. industry.

EGI also faces weather and geography issues that are similar to those in the Northeastern U.S. and which tend to increase costs. The cost of installing and maintaining distribution assets is generally greater where frost depths are deeper and ground conditions are more rocky. Both of these factors are more prevalent in Ontario and the Northeast U.S. than in much of the rest of the U.S.

Finally, the policy and regulatory environment in Ontario is more similar to that of the Northeast U.S. than much of the rest of the U.S. Most northeastern states, as well as Ontario, are emphasizing "energy transition" policies that reduce reliance on fossil fuels. Achieving energy transition goals can both decrease gas distribution output and increase some costs, both of which tend to increase the unit costs of gas distribution service. These unit cost pressures will also be more prominent in the Northeast U.S. than in the overall U.S. gas distribution industry.[14]

For all these reasons, BV believes the best inference on EGI's cost performance can be obtained by comparing the Company to the Northeast U.S. gas distribution industry and to the average performance of its seven selected peers. EGI's unit costs are approximately 48% below those of the Northeast U.S. aggregate, and approximately 30% below those of its selected peers. Unit costs that are between 30% and 48% below those of industry and peer benchmarks are indicative of very good cost performance.

5.4 Canadian Gas Distribution Industry

BV also used data from Canadian gas distributors to benchmark EGI's cost performance. Other than EGI, data were available for eight Canadian gas distributors: 1) Apex Gas (Alberta); 2) Atco Gas (Alberta); 3) Centra Gas (Manitoba); 4) Eastward Gas (Nova Scotia); 5) Liberty Utilities (New Brunswick); and 6) Fortis BC, PNG, and PNG (NE) (British Columbia).

There are several concerns associated with the Canadian gas distribution data. One is that the available data are less comprehensive than those for U.S. gas distributors. Importantly, there were not sufficient data to construct capital stocks or estimate capital costs for any sampled Canadian company other than EGI. Benchmarking analyses for Canadian gas distributors are therefore limited to O&M expenditures.

There are also concerns with distributors' reported O&M expenses, particularly regarding data comparability. Unlike U.S. gas distributors, Canadian gas distributors are not required to report output, cost, and related data on standardized forms to federal government authorities. Accordingly, Canadian gas distribution data must be collected from a number of disparate sources. Companies use different formats for itemizing and classifying O&M cost components on these data sources. These differences make it more difficult to verify that each sampled distributor is defining and measuring its O&M costs in the same way.

Notwithstanding these concerns, there is value in examining how EGI's costs compare against other gas distributors in Canada. Data on O&M costs per customer are therefore presented for EGI and the eight other gas distributors in Table 6.

[14] The U.S. west coast, particularly California, is also pursing energy transition policies. While the two dominant California gas distributors (Southern California Gas and Pacific Gas and Electric) will not be included in the EGI – Northeast regional comparison, they are considered in the peer benchmarking analysis.

Table 6: Canadian O&M per Customer Cost Benchmarking (C$)

Gas Distribution Company	O&M per Customer	Time Period
EGI		
All Regulated Operations	$217.3	2020-2022
Distribution Operations Only	$148.8	2020-2022
Other Canadian Gas Distributors		
Apex Gas	$539	2020-2022
Atco Gas	$387	2020-2022
Centra Gas	$197	2018-2020
Eastward Gas	$1158	2019-2021
Liberty Utilities	$1183	2020-2022
Fortis BC	$236	2018-2019
PNG (NE)	$624	2020-2022
PNG	$1284	2020-2022
Average Canadian O&M per customer (excluding EGI)	$701	
Difference Between EGI and sample Average Other Canadian Distributors		
All regulated operations	-69.0%	
Distribution operations only	-78.8%	

EGI's O&M costs per customer are far below comparable costs for the six other Canadian gas distributors. O&M costs per customer for the Company's overall operations and distribution operations are, respectively, 69.0% and 78.8% below the average of the eight other Canadian distributors gas distributors. Given the previously cited data limitations, these benchmarking results are less definitive than the U.S. industry analysis. However, they do not in any way undermine the U.S. evidence showing that EGI's cost performance is well above the industry average. All the benchmarking results, in turn, support a relatively low stretch factor in the Company's IRM proposal.

5.5 Relevant Empirical Evidence and Recommended Stretch Factor

The stretch factor in EGI's current IRM is 0.3%. In approving this value, the OEB rejected the argument that stretch factors should only apply to utilities transitioning from cost of service regulation to an initial IRM. This situation clearly would not apply to the Company, which has been subject to multiple, successive IRMs.

Dr. Kaufmann of the BV team agrees with the OEB's position that stretch factors can be appropriate in updated IRMs. This is evident in his previous work for OEB Staff, which included recommendations to the OEB on stretch factors in 3rdGenIR and 4thGenIR. In both 3rdGenIR and 4thGenIR, Dr. Kaufmann recommended positive stretch factors for all but the most efficient cohort of electricity distributors in Ontario. He has therefore recommended positive stretch factors for the majority of electricity distributors in Ontario in two separate IR proceedings (3rdGenIR and 4thGenIR), both of which updated previously approved IRM plans.

Dr. Kaufmann has made similar recommendations in other jurisdictions. For example, in work on behalf of several energy distributors in Massachusetts, he has recommended positive stretch factors for multiple IRM plans that were updates of previous plans.[15] To the best of his recollection, Dr. Kaufmann has *never* recommended a zero stretch factor in an IRM for a single, individual utility.

Importantly, however, he did support a zero stretch factor in both 3rdGenIR and 4thGenIR for the most efficient *cohort* of Ontario electricity distributors. These recommendations reflect his view that zero stretch factors are appropriate for utilities demonstrating excellent cost performance and/or otherwise providing value to their customers. The OEB agreed with this position in 4thGenIR, which approved zero stretch factors for electricity distributors exhibiting highly efficient cost performance.

In BV's opinion, EGI clearly exhibits highly efficient cost performance. This is true whether the Company is compared to national and regional aggregates of the U.S. gas distribution industry, or selected U.S. gas distribution peers with similar business conditions. EGI also has far lower O&M per customer costs than other Canadian gas distributors.

In addition to the benchmarking studies, other evidence from Ontario supports a reduction in EGI's stretch factor. This evidence includes an analysis indicating that customers have benefitted from previous IRMs for EGD and Union Gas. Broader developments in Ontario's electricity distribution industry also bolster the case for a lower stretch factor for EGI.

Regarding the Company's previous IRM experience, in 2011-2012, the OEB hired Dr. Kaufmann to undertake a comprehensive assessment of the IRM plans then in effect for Enbridge Gas Distribution and Union Gas. This assessment specifically addressed whether these IR plans: 1) encouraged cost control and efficiency improvements; and 2) shared these benefits with customers.

Dr. Kaufmann's findings were summarized in an April 2012 report that explored these issues in great detail, using a variety of empirical and analytical techniques.[16] The final report emphasized the importance of quantifying the distribution of benefits, noting that "while the need to design IR plans so that customers and shareholders benefit has long been acknowledged in Ontario, the distribution of benefits under IR has not (to our knowledge) been examined empirically in previous work for the Board." [17] Given the importance of this issue, he developed a rigorous yet relatively transparent methodology for quantifying the sharing/distribution of benefits under the IR plans.

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[15] Examples include Massachusetts Electric in 2018, Boston Gas in 2020, and Eversource Electric in 2022.

[16] Kaufmann, L., D. Hovde, J. Kalfayan, and M. Makos (2012) *Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans*. The report also addressed whether the companies provided appropriate service quality to their customers and was conducive to capital investment. While those objectives are obviously important, most of the analysis concentrated on the design of the IRM plans and whether these plans achieved the main objectives of IRMs to improve cost performance for the ultimate benefit of both customers and shareholders.

[17] Kaufmann, L., *op cit*, p. i.

After a comprehensive assessment, Dr. Kaufmann concluded that "the overall thrust of our analysis of prices, earnings and TFP is that IR has generated win-win outcomes for customers and shareholders."[18] Moreover, "customers captured the lion's share of benefits."[19] On average, 92.5% of measured efficiencies were distributed to EGD and Union customers, while shareholders received 7.5% of efficiency gains.[20] All else equal, EGI's previous distribution of significant efficiency improvements to its customers indicates there is less potential for incremental productivity gains in future IRMs.

The experience with stretch factors in Ontario's electricity distribution industry is also relevant to the Company. Although there are clearly differences between the gas and electricity distribution industries, there are also important regulatory parallels. For example, both industries had a "first generation" of IRM plans that were approved in 1999-2000. For a number of reasons, these initial plans were unsuccessful and were either suspended or not renewed after they expired.

However, the Natural Gas Forum ("NGF") in 2004-2005 provided a stronger, more secure foundation for incentive regulation in Ontario. [21] While this Forum explicitly focused on the natural gas industry, many of the principles articulated in the NGF proved relevant to electricity distributors as well. As a result of this stronger overall foundation, Enbridge Gas Distribution, Union Gas, and the entire Ontario electricity distribution industry have been subject to ongoing, comprehensive incentive regulation from 2008 through the present.[22]

Ontario's electricity distributors are currently subject to 4thGenIR. One interesting component of 4thGenIR is that stretch factors are linked to each company's measured cost performance under IRM. Distributors are assigned to one of five cohorts each year depending on their cost performance. All distributors in a cost cohort are assigned the same stretch factor. The values of the assigned stretch factors are inversely related to cost performance, with lower stretch factor values applied to better cost performers and vice versa.

However, if a company's measured performance in a given year improves beyond the threshold levels set by the OEB and it thereby moves into a higher-performing cost cohort, its stretch factor is reduced. Similarly, if a distributor's measured cost performance declines beyond threshold levels set by the OEB, and it thereby moves into a worse-performing cost cohort, its stretch factor is increased. Updating stretch factors in this way incentivizes distributors to make ongoing cost performance gains, and the utilities that are successful in doing so are rewarded with greater allowed revenue growth.

Interestingly, electricity distributors' stretch factors have evolved over time under this stretch factor update regime. Table 7 presents data on the distribution of stretch factors across the five stretch factor

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[18] Kaufmann, L., *op cit*, p. v-vi.

[19] Kaufmann, L., *op cit*., p. vi

[20] Kaufmann, L.., *op cit*., see Table 26, p. 111.

[21]The initial IRMs for Enbridge and Union "were viewed as trial plans of three years' duration." (Ontario Energy Board, "*Natural Gas Regulation: A Renewed Policy Framework,"* March 30, 2005, p. 14). Moreover, the initial IRM for EGD applied to only a portion of its regulated costs. While "trial plans" and partial IRMs may be informative, they are less than a firm foundation for ongoing, long-term incentive regulation.

[22] The third Generation Incentive Ratemaking proceeding began in Autumn 2007 and concluded in 2008. Between "First Generation IRM" in 2000-2001 and the commencement of 3rdGenIR in 2007, a "Second Generation IRM" took effect in December 2006. This was a transitional plan that led to only one or two rate adjustments for nearly all electricity distributors in the province, before 3rdGenIR was implemented for the industry.

options in 2013, when the IRM was first approved, and the current distribution of stretch factors following the most recent stretch factor update in 2023.[23]

Table 7: Distribution of Ontario Electricity Distributor Stretch Factors

Percentage of Ontario Electricity Distributors	2013	2023
Stretch Factor = 0%	8.2%	30%
Stretch Factor = 0.15%	20.5%	26.0%
Stretch Factor = 0.30%	45.2%	35%
Stretch Factor = 0.45%	20.5%	6%
Stretch Factor = 0.60%	3.3%	4%
Average Stretch Factor	0.29%	0.19%

In 2013, the distribution of stretch factors was similar to a classic "bell curve." A relatively small share of utilities were assigned either the lowest stretch factor value of 0% or the highest stretch factor of 0.6% per cent. Nearly 90% of distributors were clustered in the three middle stretch factor values centered around a stretch factor of 0.3%. The average stretch factor value for the industry in 2013 was 0.29%.

The current distribution of stretch factors is very different. The share of electricity distributors with 0% stretch factors has nearly quadrupled between 2013 and 2023, from 8.2% to 30% of the industry. As a result, the approximate "top third" of cost performers in Ontario's electricity distribution industry now have a stretch factor of 0%. At the other end of the spectrum, the share of distributors with a stretch factor of 0.6% has been relatively stable, increasing only from 3.3% in 2013 to 4% in 2023. Consistent with these developments, the average stretch factor value for the industry has declined from 0.29% to 0.19%.

Clearly, these data show that Ontario's electricity distribution industry as a whole has responded positively to the continuous application of IRM, and its cost performance has improved. A considerable number of electricity distributors migrated into lower stretch factor values between 2013 and 2022. Consistent with this improved cost performance, the average stretch factor value for the industry has been reduced.

BV believes Ontario's electricity distribution experience strongly supports a reduction in EGI's stretch factor. Like the electricity distributors, EGI has been continuously under IRM since 2008. The discipline and enhanced incentives of ongoing, multiple IR plans has almost certainly improved the Company's cost performance, similar to what has been observed for electricity distributors. In addition to the generally strong incentive properties of IRM, EGI's cost efficiencies are currently being augmented by savings achieved through the amalgamation of EGD and Union Gas.

The evolution of stretch factor values for electricity distributors also supports a reduction in the Company's stretch factor, particularly when benchmarking evidence for the Company is considered. EGI's current stretch factor is 0.3%, which is larger than the 0.19% stretch factor currently in effect for the *average* Ontario electricity distributor. Benchmarking comparisons show the Company's current cost performance far exceeds industry-average levels. Its unit costs are 30% to 47% below its most relevant cost comparators (*i.e.* its seven peer utilities and the Northeast gas distribution industry, respectively).

[23] Table 7 uses data on the per cent, rather than the number, of distributors with a given stretch factor because the number of distributors in the industry declined between 2013 and 2022. Comparing distributor numbers may therefore provide a misleading indicator of the evolution of stretch factors between the two years.

The Company's "top decile" performance in the North American gas distribution industry is also superior to the "top third" performance standard currently associated with zero stretch factors for Ontario's electricity distributors. In BV's opinion, EGI's performance levels are commensurate with the OEB's thresholds used to assign electricity distributors to the "top cohort" of zero stretch factors

In addition to the benchmarking and other related empirical evidence, it is important to recognize that EGI customers will benefit from productivity and operational gains that are flowed through to 2024 rates. This is the first year of the new incentive regulation mechanism, and customers will receive a sizeable and immediate benefit in that year as cost savings are rebased into 2024 rates. These costs savings reflect ongoing, integration efficiencies that have been made possible by the amalgamation, as well as the Company's continuous, aggressive pursuit of productivity gains.

EGI will pass through $121.2 million of net integration and productivity savings into 2024 rates. In addition to these cost savings, the settlement approved in August 2023 will reduce 2024 customer rates by an additional $67.5 million. Customers' 2024 rates will therefore be reduced by $188.7 million in achieved and/or approved cost savings, which represents a price reduction of approximately 6.1% at the outset of the next PBR plan.

These rebased cost savings further support the recommendation of a zero stretch factor. Customers will benefit from the new IRM immediately, since productivity and integration savings are reflected in lower rates from the outset of the new plan. Since rebased cost savings generate immediate customer benefits, there is less need to rely on the stretch factor to ensure that customers will benefit under the Company's new PBR proposal.

Even more importantly, passing cost savings to customers in rebased rates will typically create more benefits for customers than passing an equivalent magnitude of benefits to customers through the stretch factor. The reason is simply that rebased cost savings benefit customers in year one of the plan. In contrast, customers must wait for the stretch factor to distribute benefits, since this occurs for the first time when the revenue adjustment mechanism takes effect in year two of the plan.

Lower rebased rates will benefit customers beyond the first plan year. In year two of a PBR plan, revenue adjustment mechanisms are applied to revenues from the preceding, "cast-off" year. The amount of additional revenue generated by the IRM adjustment will naturally be smaller for smaller values of cast-off revenues. Therefore, when rebased cost savings reduce cast-off revenues, they simultaneously reduce the amount of additional revenue resulting from IRM revenue adjustment formulas in year two and, in fact, every other succeeding year of the IRM.

Passing cost savings into rebased cast-off rates therefore has ripple effects that reduce rate changes in each year of an IRM. This is analogous to how the stretch factor reduces revenues in each plan year. However, rebased cost savings reduce revenue changes by reducing the revenue base to which PBR adjustment formulas are applied, while the stretch factor reduces the rate of change of adjustment formulas directly.

Because rebased cost savings reduce revenues in year one of the PBR plan and each successive year, while the stretch factor reduces revenue changes only when revenue adjustment mechanisms are applied, it follows that in a five-year PBR plan, rebasing cost savings in updated revenues will lead to five years of lower prices for customers, while the application of the stretch factor leads to only four years of customer benefit. All else equal, rebasing cost savings is thereby likely to create greater benefits for customers than a stretch factor of equal magnitude. The cost savings rebased in 2024 revenues will therefore benefit EGI customers in all five years of the Company's IRM. The magnitude of those benefits over the IRM term will almost certainly exceed the benefits generated by a conventional stretch factor.

Given EGI's exceptional benchmarking results, other relevant evidence in Ontario, and the Company's commitment to increase customer benefit by rebasing $188.7 million of cost savings in 2024 rates, BV recommends a stretch factor of zero for EGI's IRM proposal.

6.0 Recommendations for IRM

6.1 Inflation Factor

BV recommends an industry-specific inflation factor for EGI's IRM. Industry-specific inflation factors are more compatible with the competitive market paradigm that underpins the development of IRMs. Ontario's experience also shows that industry-specific inflation factors can be practical and relatively easy to implement.

BV recommends that the inflation factor in EGI's IRM be computed as a weighted average of growth in the Canadian GDP-IPI-FDD and the Ontario Average Hourly Earnings indexes. A 75% weight is recommended for the GDP-IPI-FDD and a 25% weight proposed for the AHE. These weights are generally consistent with the shares of labour and non-labour costs for both EGI and U.S. distributors.

6.2 Productivity Offset

In IRM plans with industry-specific inflation factors, the productivity offset component of the X factor should be equal to the long-run TFP trend for the respective utility industry. Based on a TFP study of the U.S. gas distribution industry, Dr. Kaufmann recommends a productivity offset of -1.52%. This value is equal to the long-run TFP trend for U.S. gas distributors over the 2006-2022 period.

BV's estimated TFP trend is also broadly supported by PEG's 2018 TFP study for OEB Staff. This study found TFP growth in the U.S. gas distribution industry grew by -0.55% per annum over the 2001-2016 period. PEG's 2018 study also estimates that this negative TFP trend is accelerating (*i.e.* becoming more negative) over time. If PEG's previous findings continued over the 2016-2022 period, its current estimate of industry TFP would be more negative.

BV's recommended productivity offset is also consistent with values recently approved in other jurisdictions. In addition to Ontario, the most active PBR jurisdiction in North America over the last decade has been Massachusetts. In 2020, the Massachusetts Department of Public Utilities ("DPU") approved a five-year, inflation minus X PBR plan for NSTAR Gas. The approved productivity offset in this plan was -1.18%. In 2021, the DPU approved a five-year, inflation minus X PBR plan for National Grid/Boston Gas. The approved productivity offset in this plan was -1.30%.[24]

In addition to Ontario and Massachusetts, Alberta has become the third leading PBR/IRM jurisdiction in North America. In October 2023, the Alberta Utilities Commission approved its third, five-year PBR plan.[25] Both the second ("PBR2") and third ("PBR3") PBR plans approved in Alberta included I-X indexing formulas similar to those used in Ontario and Massachusetts.

However, PBR2 and PBR3 also include a significant expansion of the I-X framework used to update utilities' allowed revenues. In addition to this formula, PBR2 and PBR3 also include a "kbar" mechanism,

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[24] As discussed in Section 3, the productivity offset in Massachusetts includes estimates of productivity and input price differentials and therefore depends on more than just the industry TFP trend. Nevertheless, the fact that regulators have since 2020 approved negative X factors in gas distribution PBR plans is a new and relevant development.

[25] Decision 273888-DOI-2023, Alberta Utilities Commission, 2024-2028 PBR Plan for Alberta Electric and Gas Distribution Utilities, October 4, 2023.

which provides another, independent source of revenues for utilities. As a result, the Alberta PBR plans are not simply I-X mechanisms; they are more accurately described as I-X+K plans.

The Decision in PBR3 provides a detailed discussion of the motivation for, and basic features of, Alberta's I-X+K framework. A careful examination of this Decision is valuable for understanding Alberta's regulatory framework and how its "X plus K" factors compare with the X factors approved in Ontario and Massachusetts.

Early in the Decision, the AUC states that

> "Ideally, assuming overall sectoral productivity, the utility's overall revenue under PBR would increase at a rate under inflation. *This is another ideal that is difficult to achieve in reality*." (italics added) [26]

In other words, the AUC says an ideal I - X PBR plan would increase utility's revenue at a rate below the inflation rate. This necessarily implies a positive X factor, since an X factor of zero increases revenues at the same rate as inflation, and a negative X factor increases revenues more rapidly than inflation. However, the AUC finds this desirable PBR ideal is "difficult to achieve in reality."

To develop a realistic regulatory framework that preserves I-X rate adjustments below inflation:

> "The Commission finds that supplemental capital funding, in addition to revenues provided under I-X and other available mechanisms (such as Y and Z factors) is required for the PBR3 term. This funding will consist of a K-bar and Type 1 capital tracker mechanisms, as well as alternative remuneration on a pilot basis…The Commission emphasizes that K-bar funding is not intended to provide funding for projects on a line-by-line basis, but rather is to supplement capital under the basic PBR I-X indexing mechanism as necessary to provide an envelope of funding for the management of business-as-usual activities with a reasonable opportunity to earn the approved rate of return[27]

The k-bar mentioned above is computed on a company-specific basis using data on the company's own recent trend in capital expenditures. The k-bar mechanism is therefore formulaic in nature, and it does create some positive incentives, since the calculated k-bar amounts are developed through formulas exogeneous to the company, rather than any company's current capital costs. The k-bar is also available to all companies, which differs fundamentally from the capital "modules" approved by the OEB. Those modules require company applications subject to OEB review and approval. The AUC reviews only whether the k-bar is calculated correctly and not whether a k-bar is allowed (it is).

The passage also reveals other important aspects of the k-bar. First, it is "supplemental capital funding," in addition to revenues provided for capital investment under the I-X mechanism as well as "related mechanisms such as the Y and Z factors. The AUC also "emphasizes K-bar funding is…intended to… supplement capital under the basic PBR I-X indexing mechanism"(and)… provide an envelope of funding for the management of business-as-usual activities with a reasonable opportunity to earn the approved rate of return. The K-bar is therefore a source of supplemental revenues, in addition to revenues provided under the I-X formula, to fund and manage *business as usual activities* (emphasis added). The

[26] AUC, *op cit*, p.6
[27] .AUC, *op cit*, p. 45

k-bar is not used to fund energy transition and related policy initiatives; those costs are recovered through the Type 1 capital tracker mentioned above.

In addition, "the Commission finds that supplemental capital funding is required for… ensuring that the distribution utilities continue to have a reasonable opportunity to recover their prudent costs and earn a fair return." Indeed, Table 6 of the AUC Decision computes how ROEs would have been affected in PBR2 if the k-bar was not available. The AUC's analysis shows that, in the absence of the kbar, none of the six Alberta utilities earned their allowed rate of return of 8.5%. The utilities' average rate of return over the five-year term of PBR2 would have been 5.32% .

In light of these results, it is not surprising that parties were nearly unanimous in supporting the continued use of, incremental capital funding mechanisms in PBR3. Parties generally supported the continued use of the Type 1 capital tracker mechanism for extraordinary capital additions and the K-bar mechanism for all other capital expenditures not qualifying for Y, Z or Type 1 treatment.[28] The AUC also reiterated that, "in the Commission's view, K-bar provides an envelope of funding that is based on the assumption that it is reasonable to expect that the distribution utilities will be able to manage their business-as usual capital activities and have a reasonable opportunity to earn an approved rate of return, if they are provided with a level of supplemental capital commensurate with their actual experience during the prior PBR term."[29] Moreover, the AUC noted that k-bar revenues are not even restricted to capital expenditures, stating that "the Commission expects that given the total envelope of funding provided under the PBR3 plan, distribution utilities should have the flexibility to support both capital and O&M expenditures."[30]

In sum, the k-bar was established to supplement revenues provided by the I-X mechanism. Additional revenues were necessary because the AUC was, by all appearances, not willing to implement a negative X factor, as several utilities requested in both PBR1 and PBR2. Although the k-bar is different in some respects from the I-X mechanism, there are also important similarities. First, both are formula-based mechanisms. Relatedly, they both create strong performance incentives. They are also designed to support utilities' ongoing "basic business" rather than address one-time or extraordinary costs. Finally, the I-X and k-bar revenues are fungible, and can be used to fund both capital and operating spending programs.

When seen in this perspective, Alberta's approved X and K factors are clearly congruent with Massachusetts' approved negative X factors, as well as BV's recommended negative X factor for EGI. Regulators in Massachusetts and Alberta both approved IRMs that explicitly allow utility revenues to grow more rapidly than general inflation. Massachusetts has done so directly, in light of evidence showing that input quantity growth for utility industries has outpaced output growth. Alberta achieved this aim by expanding the I-X framework to include a new, incentive compatible mechanism that was intentionally designed to provide revenues beyond those that are generated by the I-X formula. The transformation from I-X to I-X+K in Alberta becomes functionally equivalent to a negative X factor

[28] AUC, *op cit*, p. 47.
[29] AUC, *op cit*, p. 52.
[30] AUC, *op cit*, p. 54.

whenever the value of the kbar exceeds the value of (-X). This proved to be true for all six utilities in Alberta in PBR2.

The most recent PBR decision in Massachusetts provides more direct evidence that negative X factors in Massachusetts and k-bar mechanisms in Alberta are alternative means of achieving the same end: enabling utility revenue adjustment mechanisms to grow more rapidly than general inflation rates (which is, in turn, just and reasonable given current utility industry conditions). In 2022, Eversource Energy filed a PBR proposal for its electricity distribution operations. The PBR proposal included an inflation minus X mechanism, with a recommended X factor of -1.50% (i.e. the same value of the productivity offset currently recommended for EGI).

However, while that PBR proposal was subject to discovery and regulatory review, Eversource carefully examined options for modifying its PBR proposal. In particular, the company considered the option of eliminating its negative X 1.50% factor, and instead setting the value of X to zero, in exchange for a k-bar mechanism. In rebuttal testimony, Eversource did in fact propose this alternative PBR mechanism.

The Massachusetts Department of Public Utilities approved this option and thereby reduced Eversource's proposed X factor from -1.50% to zero while simultaneously adding a k-bar mechanism to provide additional revenues. This experience clearly demonstrates that negative X factors and k-bar mechanisms are substitutable means of achieving the same end: enabling IR mechanisms to increase utility revenues at a rate exceeding the general inflation rate. Regulators in both jurisdictions have found this to be necessary given current business conditions for gas and electric utilities. And while Massachusetts and Alberta have traditionally used different means to achieve this end, recent experience shows a degree of convergence between their approaches, with k-bars and negative X factors being used interchangeably to provide sufficient revenues to utilities while at the same time preserving strong performance incentives.

Both the current study and recent precedents provide compelling evidence that TFP trends have turned negative for North American gas distributors. Some regulators have accordingly approved negative X factors. Others have introduced new regulatory mechanisms that can, in principle, allow for revenue trends that are functionally equivalent to negative X factors.

However, in Dr. Kaufmann's experience, the concept of negative X factors sometimes raises unfounded concerns among stakeholders. Three of the most common unfounded concerns are: 1) negative X factors will undermine performance incentives; 2) negative X factors are equivalent to declining efficiency and therefore incompatible with incentive regulation; and 3) negative X factors lead utility rates to rise more rapidly than general inflation, which is not reasonable under effective incentive regulation. There is no merit to any of these concerns.

First, incentive regulation theory is founded on the premise that utility managers, like managers of other businesses, will respond rationally to incentives.[31] In PBR/IRM plans, incentives are created by

[31] More descriptively, incentive regulation uses "carrots" to motivate better performance. The notion that negative X factors undermine incentives seems to view the X factor as a "stick," where higher X factors will

establishing price trends that are "external" to the company's own costs. This is analogous to competitive markets, where prices are determined by market-wide forces rather than any individual company's own costs. When prices are determined by external forces, companies have stronger incentives to control costs since doing so does not impact their prices but does reduce their cost which, in turn, improves the bottom line.

This process is replicated in incentive regulation. Indeed, as discussed in Section 2 of this report, incentive regulation uses a competitive market paradigm to establish price trends that simulate competitive market outcomes where competition itself is impractical While the utility is under an IRM, its price trends are determined by changes in industry-wide changes in input price inflation and TFP growth. The company's own costs are "external" to these industry-wide forces, so the utility has incentives to reduce costs. Moreover, these incentives are not impacted in any way by the values of the inflation measure or TFP trends used to set external price trends. Therefore, negative TFP trends do not undermine performance incentives.

Second, negative X factors are not equivalent to declining efficiency. This view implicitly treats "productivity" and "efficiency" as identical concepts. This is not the case in productivity measurement, or in how productivity measures are used in incentive regulation.

Dr. Kaufmann has examined the relationship between changes in total factor productivity and changes in cost efficiency in previous reports to the OEB. At the outset of 4thGenIRM, he prepared a detailed "Concept Paper" that addressed this relationship, as well as other similar topics.[32] His analysis showed mathematically that TFP change is a much broader concept than changes in efficiency. Improved efficiency is only one component of productivity change. In addition, productivity change captures the impact of technological change, economies of scale, economies of density, the system age of assets, changes in public policy, and other factors. TFP trends therefore can, and will, capture the impacts of all these developments, some of which will tend to reduce measured TFP and potentially lead to negative industry TFP trends. Thus, negative X factors are not synonymous with declining efficiency.

Finally, negative X factors that cause utility prices to increase more rapidly than general inflation can be reasonable under incentive regulation. It is important to recognize that economy-wide inflation indices necessarily measure average inflation within an economy. At any given time, approximately 50% of economic activity will exhibit above-average price inflation, while roughly 50% of economic activity will display below-average price growth.

A negative X factor for EGI simply means that, for the time being, the Company is within the 50% of the economy experiencing above-average inflationary pressures. This should not be surprising, since output growth is slowing in the natural gas industry at the same time that capital and O&M spending are increasing. This combination is putting upward pressure on the industry's unit costs, which will inevitably require increases in outprice prices, regardless of how the Company is regulated. Indeed, by creating stronger performance incentives, incentive regulation is likely to lead to lower rate changes than the Company would need to request under cost of service regulation to recover its increasing costs.

"force" a utility to work harder to be rewarded. The latter view is more reminiscent of traditional regulation (*i.e.* using prudence reviews to "find" efficient costs) and is antithetical to designing more incentive-compatible regulatory frameworks that encourage efficiencies that benefit both customers and shareholders.

[32] See "*Defining, Measuring, and Evaluating the Performance of Ontario Electricity Networks*: *A Concept Paper*, April 2011, L. Kaufmann. Most of this discussion is on pp. 22-27.

Therefore, a negative X factor is reasonable for the Company given the current cost and output realities facing the natural gas distribution industry.

While the OEB has not yet approved a negative X factor in an IRM, it should not be concerned that doing so would be contrary to effective incentive regulation. Whenever business and regulatory conditions put sufficient upward pressure on a regulated industry's unit costs, a negative X factor is both appropriate and warranted. There is abundant empirical and industry evidence to support the conclusion that this is currently the case for the North American gas distribution industry. BV believes that this evidence supports its recommended productivity offset of -1.5%.

6.3 Stretch Factor

BV recommends a stretch factor of zero. The cost benchmarking study indicates that EGI is a top decile cost performer and therefore has less potential to achieve efficiency gains than much of the rest of the industry. Over the 2020-2022 period, the Company's average unit cost was 47.6% below the average unit cost of gas distributors in the Northeast U.S., 29.1% below average unit costs of the entire U.S. gas distribution industry, and 30.6% below the average unit cost of selected gas distribution peers. All the benchmarking evidence supports the view that EGI is a very good cost performer, but BV believes the Northeast U.S. aggregate is a more relevant comparator than the overall U.S. industry since this region operates under a business and regulatory/policy environment more similar to Ontario's than much of the rest of the U.S. gas distribution industry.

Other evidence from Ontario supports BV's recommended stretch factor. Previous assessments of Company IRM plans indicate that the lion's share of achieved cost savings in these plans have been distributed to customers. All else equal, this reduces the Company's potential to achieve incremental cost performance gains.

The evolution of stretch factor values for Ontario electricity distributors also supports BV's recommendation. Like the electricity distributors, EGI has been continuously under IRM since 2008. The discipline and enhanced incentives of ongoing, multiple IR plans has almost certainly improved the Company's cost performance, similar to what has been observed for electricity distributors. In addition to the generally strong incentive properties of IRM, EGI's cost efficiencies are currently being augmented by savings achieved through the amalgamation of EGD and Union Gas.

EGI's current stretch factor of 0.3% also exceeds the 0.19% stretch factor currently in effect for the average Ontario electricity distributor. EGI's 0.3% stretch factor is inconsistent with benchmarking comparisons showing the Company's current cost performance is above industry-average levels by a wide margin. Indeed, the Company's current cost performance is commensurate with the thresholds the OEB has used to assign zero stretch factors to electricity distributors.

In addition to the benchmarking and other related empirical evidence, it is important to recognize that EGI customers will benefit from productivity and operational gains that are flowed through to 2024 rates. This is the first year of the new incentive regulation mechanism, and customers will receive a sizeable and immediate benefit in that year as cost savings are rebased into 2024 rates. These costs savings reflect ongoing, integration efficiencies that have been made possible by the amalgamation, as well as the Company's continuous, aggressive pursuit of productivity gains.

EGI will pass through $121.2 million of net integration and productivity savings into 2024 rates. In addition to these cost savings, the settlement approved in August 2023 will reduce 2024 customer rates by an additional $67.5 million. Customers' 2024 rates will therefore be reduced by $188.7 million in achieved and/or approved cost savings, which represents a price reduction of approximately 6.1% at the outset of the next PBR plan.

These rebased cost savings further support the recommendation of a zero stretch factor. Customers will benefit from the new IRM immediately, since productivity and integration savings are reflected in lower rates from the outset of the new plan. Since rebased cost savings generate immediate customer benefits, there is less need to rely on the stretch factor to ensure that customers will benefit under the Company's new PBR proposal.

Even more importantly, passing cost savings to customers in rebased rates will typically create more benefits for customers than passing an equivalent magnitude of benefits to customers through the stretch factor. The reason is simply that rebased cost savings benefit customers in year one of the plan. In contrast, customers must wait for the stretch factor to distribute benefits, since this occurs for the first time when the revenue adjustment mechanism takes effect in year two of the plan.

Lower rebased rates will benefit customers beyond the first plan year. In year two of a PBR plan, revenue adjustment mechanisms are applied to revenues from the preceding, "cast-off" year. The amount of additional revenue generated by the IRM adjustment will naturally be smaller for smaller values of cast-off revenues. Therefore, when rebased cost savings reduce cast-off revenues, they simultaneously reduce the amount of additional revenue resulting from IRM revenue adjustment formulas in year two and, in fact, every other succeeding year of the IRM.

Passing cost savings into rebased cast-off rates therefore has ripple effects that reduce rate changes in each year of an IRM. This is analogous to how the stretch factor reduces revenues in each plan year. However, rebased cost savings reduce revenue changes by reducing the revenue base to which PBR adjustment formulas are applied, while the stretch factor reduces the rate of change of adjustment formulas directly.

Because rebased cost savings reduce revenues in year one of the PBR plan and each successive year, while the stretch factor reduces revenue changes only when revenue adjustment mechanisms are applied, it follows that in a five-year PBR plan, rebasing cost savings in updated revenues will lead to five years of lower prices for customers, while the application of the stretch factor leads to only four years of customer benefit. All else equal, rebasing cost savings is thereby likely to create greater benefits for customers than a stretch factor of equal magnitude. The cost savings rebased in 2024 revenues will therefore benefit EGI customers in all five years of the Company's IRM. The magnitude of those benefits over the IRM term will almost certainly exceed the benefits generated by a conventional stretch factor.

In light of all this evidence, BV believes all this evidence supports a recommended stretch factor of zero.

7.0 Technical Appendix

7.1 Capital Costs

A service price approach was used to compute capital quantities and capital costs. BV's approach has a solid basis in economic theory, and its general approach is employed by the U.S. Bureau of Labor Statistics ("BLS") when estimating multi-factor productivity ("MFP") growth for the aggregate U.S. economy and important economic sectors. The BLS has been estimating U.S. MFP growth since the early 1980s, when it became the first government agency in the world to develop MFP estimates.[33] The approach controls for differences across utilities in the age of plant additions. It improves on standard utility accounting of capital costs, which is based on a book valuation of capital and therefore does not reflect inflation in the value of capital assets.

Capital cost in year t (CK_t,) is the product of a capital service price index, WKS_t, and a capital quantity index, XK_{t-1}.

$$CK_t = WKS_t \cdot XK_{t-1}$$

The capital quantity index is constructed using inflation-adjusted data on the value of utility plant. Each service price index measures the hypothetical, competitive market price of capital services provided by assets. Price and quantity indexes both depend on a mathematical characterization of the process of plant depreciation.

The following formula was used to compute values of the capital quantity index:

$$XK_t = XK_{t-1}*(1-d_t) + (\text{Capital Additions}_t/PK_t)$$

Here, the quantity of capital input in year t is equal to capital quantity in the previous year t-1, minus the depreciation on the preceding year's capital quantity, plus capital additions in year t deflated by an asset price index in year t (PK_t). BV used Handy-Whitman data on gas distribution capital costs and quantities to calculate the asset price index PK.

In constructing capital quantity and cost indices for the US sample, we took 1998 as the benchmark year. We estimated the benchmark capital value by subtracting accumulated depreciation in 1998 from 1998 gross plant for both distribution and general plant and adding distribution plus general net plant values together.[34] This sum was then divided by a "triangularized" weighted average of the values of the producer price index. A triangularized weighting gives greater weight to more recent values of the producer price index.[35]

The *d* variable refers to depreciation, which is discussed further below.

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[34] S&P's dataset has some missing values for 1998 accumulated depreciation. BV interpolated the value of 1998 accumulated depreciation using surrounding values for three sampled utilities: Atlanta Gas Light, Niagara Mohawk Power, and Public Service Electric and Gas.

[35] For example, in a triangularized weighting of 20 years of index values, the oldest index value has a weight of 1/210, the next oldest index has a value of 2/210, and so on. 210 is the sum of the numbers from 1 to 20. A discussion of triangularized weighting of asset price indexes is found in Stevenson (1980).

7.2 Depreciation and Capital Quantity

The MAADs proceeding that approved EGI's current IRM (EB-2017-0306/EB-2017-0307) involved a vigorous debate over depreciation. The Company's consultant, National Economic Research Associates ("NERA") advocated what is known as One Hoss Shay ("OHS") depreciation. Under OHS, assets retain their full level of productive efficiency from the time they are installed until the time they are retired, at which point they depreciate entirely.

In contrast, OEB Staff consultant PEG recommended a geometric decay ("GD") approach to depreciation. Under GD, assets lose productive efficiency at a constant percentage rate every year they are in place. PEG identified a number of concerns with the OHS approach.

In its Decision, the OEB did not make any specific findings on the appropriate TFP methodology. Accordingly, it did not assess the merits of the OHS and GD depreciation alternatives. In past Decisions, however, the OEB has been critical of OHS and relied on TFP studies that used geometric decay.

In previous TFP and benchmarking work for OEB Staff, Dr. Kaufmann used a GD depreciation approach. He has also echoed some of PEG's concerns regarding OHS. Notwithstanding those precedents, there are legitimate concerns with geometric decay, and these concerns should be acknowledged and examined. While a complete analysis of the merits of GD, OHS and other depreciation approaches is complex and goes beyond the scope of this Appendix, in Dr. Kaufmann's opinion the two main concerns with GD depreciation are: 1) it conflicts with the gas distribution industry's experience and understanding of how gas distribution assets depreciate over time; and 2) assets *never* fully depreciate under geometric decay.

On the first point, Dr. Kaufmann has interacted with utility engineering and operational professionals many times, and in diverse locations, over the last 25 years. These experts overwhelmingly believe that gas distribution assets show little physical decay or loss of efficiency in the years immediately after they put in place. Instead, the industry's accumulated experience is that newly-installed gas distribution assets are "like new" for several, and sometimes many, years. However, as assets progress towards the end of their useful lives, they begin to perform less efficiently, and efficiency losses accelerate as assets approach the time when they are retired.

This accumulated industry expertise is essentially the opposite of how assets depreciate under GD. Geometric decay assumes that assets decline at a constant percentage rate every year they are in use. For example, suppose capital additions of $1,000,000 are made in year one and the assumed depreciation rate is 5%. Under GD, the measure of physical capital services provided by this capital investment over the first four years of its life will be:

Year (January 1)	Measured Efficiency Services	Loss of Efficiency Services
One	$1,000,000	
Two	$950,000 [=$1,000,000*(1-.05)]	$50,000

Three	$902,500 [=$950,000*(1-.05)]	$47,500
Four	$857,375 [=$902,500 *(1-.05)]	$45,125

After the initial capital investment in year one, capital additions lose $50,000 of productive services by the beginning of year two. They lose an additional $47,500 of efficiency by the beginning of year three, and lose an additional $45,125 of productive efficiency by the beginning of year four. An identical decay process occurs in each subsequent year, where physical capital services in year *t* are equal to services provided in year *t-1* minus five per cent depreciation of year *t-1* capital services.

The capital investment therefore loses more productive services during the first year of operation than during the second year, and it loses more capital services during the second year of operation than it does in the third year. This pattern continues in each subsequent year of the assets' remaining life. Under GD, capital therefore loses the greatest amount of its productive efficiency during the first year of operation, and as capital ages the incremental loss of efficiency declines in each subsequent year.[36]

This pattern of depreciation essentially inverts the industry's accumulated expertise. Industry professionals believe new gas distribution assets operate "like new," with little to no significant decay, immediately after they are installed. Under GD, depreciation is front-loaded, with the greatest amount of decay occurring during the first year of operation. Industry professionals believe depreciation increases as assets age and approach the end of their useful lives. Under GD, depreciation tapers off as assets age.

This decay pattern also sheds light on the concern that assets never fully depreciate under GD. Assets that decay at a constant percentage rate will approach a value of zero efficiency services as time goes toward infinity, but they can never reach that value in any finite period. Every gas distribution asset installed must therefore provide a non-zero level of measured efficiency services under GD. Taken at face value, this means that no gas distribution asset ever fully depreciates and every gas distribution asset provides some productive services forever, which is obviously not accurate.

Dr. Kaufmann chose a depreciation approach, known as hyperbolic decay, that avoids the unrealistic and problematic implications of the OHS and GD options debated in Ontario. This approach has been used less often in regulatory proceedings, but it has been employed for decades by the BLS to compute TFP growth in the U.S. economy. The BLS is a highly-respected institution and authority on TFP and related measurement issues. It chose the hyperbolic decay approach only after thorough examination of all depreciation options, including OHS and GD.[37]

[36] This example focuses on the "age-efficiency" profile, which measures capital efficiency and services *per* se. The "age-value" profile concerns changes in the value of capital assets over time.

[37] This examination took place in the early 1980s and involved many leading experts on depreciation and capital measurement. Until that time, the BLS had only provided measures of labor productivity for the aggregate economy and different economic sectors. It was tasked with developing multi-factor productivity measures in the early 1980s.

Under hyperbolic decay, capital services are computed using the hyperbolic function below:

$$S_t = \frac{N - t}{N - \beta t}$$

Here, S_t is the relative efficiency of assets in year t, N is asset service life, and β is a parameter reflecting the rate of decay. In its computation of TFP growth for the U.S. economy, the BLS computes capital services provided by structures using a value of 0.75 for β, and the same value for β is used in this study. Drawing on the most recent National Grid precedent, the service life for assets is 51 years. Under this hyperbolic decay formula, assets retain nearly all their productive efficiency during their early years of operation. Efficiency losses increase as assets age, and assets are fully depreciated in the last year of their service life.

Another benefit of the hyperbolic decay approach is that it is better tailored to the "vintaging" of each distributor's assets. The average loss of asset efficiency depends on capital investment patterns, which will differ both across time and across different distributors in the sample. The application of the hyperbolic formula captures differences in asset vintaging, both across time and across sampled companies. In contrast, the geometric decay approach assumes a single depreciation rate that applies in each year to every distributor.

7.3 Capital Input Price

The price of capital input is equivalent to the implicit rental price associated with the perpetual inventory equation. The implicit rental price formula is based on an equilibrium relationship between the price an investor is willing to pay for an asset and the after-tax expected value of services that the asset will provide over the asset's lifetime. Implicit rental price formulas are derived using rigorous mathematical techniques, but the formulas resulting from this process are sometimes critiqued as being opaque and difficult to interpret or understand.

The capital input price used by BV is based directly on the capital input price formula used by BLS when estimating MFP growth for the U.S. economy. Dr. Kaufmann of the BV team consulted directly with BLS personnel to ensure that the capital input price in this study was as consistent as possible with the BLS formula. Recall that the BLS uses a hyperbolic decay approach to depreciation, which BV also utilizes in this study. The BLS capital input price is therefore also consistent with hyperbolic decay.

In each year t, the capital service price is given by the formula below:

$\text{Rental price}_t = [PK_t\ ((R\text{-}I)\text{-}D_t)\text{-}\%\Delta PK_t]\ *[(1\text{-}uz)_t/(1\text{-}u)_t]$

In this equation, PK is the capital asset price, (R – I) is a measure of the real internal rate of return, D is the loss of efficiency services, u is the corporate tax rate, and z is the present value of each dollar of depreciation deduction.

As previously explained, PK was computed for each year using Handy-Whitman data. The value of %ΔPK is equal to the average change in this capital asset price over the most recent three years. The value of R was measured by Moody's AAA bond rate data. The value of I was measured by the CPI. The value of D was computed directly using the hyperbolic decay formula, as applied to each utility's capital stock. Corporate tax rates were the sum of federal and state (or provincial) tax rates paid by each distributor. The value of z was computed using the sum of digits method.

It is not unusual in empirical work to smooth some of these variables that are especially volatile from year to year. BV used smoothed values of the real internal rate of return and the value of z, using the average value of each over the 1998-2020 period. Depreciation was also smoothed using a three-year, moving average approach.

While the capital input price is somewhat complex, closer inspection shows that most of its elements can be interpreted and understood. It can be seen that the value of the rental price is positively related to the capital asset price PK and the real rate of return on capital (R-I). This is intuitive, because payments for capital services should clearly increase as the prices of capital assets themselves rise and as real returns on assets increase.

It can also be seen that the capital service price is negatively related to the values of depreciation D and the effective tax rate after deductions, uz. Again this is intuitive, because capital becomes less valuable as it depreciates and as taxes on capital returns increase.

The remaining element in the formula is %ΔPK, which is sometimes described as asset capital gains. This element is less easy to interpret, and it has in fact been controversial in academic research. Because of these controversies, some analysts do not include this term in capital service prices. However, this term is included in BLS's capital price measure, and it has theoretical support. It has accordingly been retained in BV's work.[38]

7.4 O&M Costs

For every sampled gas distributor, total O&M expenses were computed as:

Total Distribution O&M Expenses plus

Total Underground Storage Expenses plus

Total Other Storage Expenses plus

Customer Service & Information Expenses plus

Customer Accounts Expenses plus

Sales Expenses *minus*

Franchise Requirements (acct 927) *minus*

Maintenance of General Plant (acct 932) *minus*

Uncollectible Accounts (acct 904) *minus*

Proxy for DSM expenses (acct 905 for MA distributors, acct 908 for all others) **plus**

Allocated A&G expenses, equal to total gas A&G multiplied by (Gross gas distribution plant divided by total gas plant), in each sample year

[38] In the 2018 TFP study submitted on behalf of OEB Staff, PEG also smoothed its measure of the real rate of return. PEG's capital service price does not utilize a "z" term. In the past PEG has included a similar capital gains term in its capital service price, but to the best of our knowledge no longer does so.

7.5 Sampled Gas Distributors

Table 8: Sampled Gas Distributors

Sample Company	
Atlanta Gas Light Company	North Shore Gas Company
Avista Corporation	Northern Illinois Gas Company
Baltimore Gas and Electric Company	Northern Indiana Public Service Company
The Berkshire Gas Company*	Northern States Power Company
Black Hills Energy Arkansas, Inc.	Ohio Gas Company
Bluefield Gas Company	Orange And Rockland Utilities, Inc.*
Boston Gas Company*	Pacific Gas and Electric Company
Brooklyn Union Gas Company*	The Peoples Gas Light and Coke Company
Cascade Natural Gas Corporation	Peoples Gas System
Central Hudson Gas & Electric Corporation*	Public Service Company Of North Carolina, Inc.
Colonial Gas Company*	Public Service Electric and Gas Company*
Columbia Gas of Kentucky, Inc.	Puget Sound Energy, Inc.
Columbia Gas of Maryland, Inc.	Questar Gas Company
Connecticut Natural Gas Corporation*	Rochester Gas and Electric Company*
Consolidated Edison Company Of New York, Inc.*	South Jersey Gas Company*
Consumers Energy Company	Southern California Gas Company
Corning Natural Gas Corporation*	The Southern Connecticut Gas Company*
Delta Natural Gas Company, Inc.	Southern Indiana Gas and Electric Company
DTE Gas Company	St. Joe Natural Gas Co, Inc.
Duke Energy Ohio, Inc.	St. Lawrence Gas Company, Inc.*
Louisville Gas and Electric Company	Superior Water, Light and Power Company
Madison Gas and Electric Company	The East Ohio Gas Company
Mountaineer Gas Company	Virginia Natural Gas, Inc.
National Fuel Gas Distribution Corporation*	Washington Gas Light Company
New Jersey Natural Gas Company*	Wisconsin Gas LLC
New York State Electric & Gas Corporation*	Wisconsin Power and Light Company
Niagara Mohawk Power Corporation*	Yankee Gas Services Company*

7.6 Annual TFP Results

Table 9: Annual TFP Results

Year	% Change Output	% Change Input	% Change TFP	% Change Labour	% Change Non-Labour O&M	% Change Capital
2006						
2007	0.76%	3.00%	-.2.24%	-7.48%	0.26%	2.73%
2008	0.54%	1.07%	-0.54%	-1.37%	-0.08%	2.78%
2009	0.13%	4.40%	-4.27%	5.03%	7.02%	2.64%
2010	0.55%	1.46%	-0.92%	-2.22%	1.89%	2.73%
2011	0.48%	1.39%	-0.91%	-1.12%	0.14%	3.03%
2012	0.48%	0.79%	-0.31%	-2.52%	-1.23%	2.84%
2013	0.64%	3.43%	-2.80%	3.84%	3.67%	3.19%
2014	0.54%	1.63%	-1.10%	-1.05%	-0.84%	3.65%
2015	0.82%	2.01%	-1.20%	-2.19%	-.02%	4.24%
2016	0.87%	3.49%	-2.62%	1.47%	2.98%	4.39%
2017	0.75%	2.67%	-1.92%	0.48%	1.12%	4.24%
2018	0.88%	4.96%	-4.08%	5.70%	6.15%	4.07%
2019	0.83%	2.24%	-1.41%	-110%	0.66%	4.25%
2020	0.71%	0.81%	0.10%	-2.86%	-1.72%	3.49%
2021	1.76%	1.04%	0.72%	4.82%	-0.10%	0.15%
2022	0.13%	0.73%	-0.60%	-0.16%	-0.455%	3.59%
Avg. 2006-22	0.68%	2.20%	-1.52%	0.91%	0.97%	3.25%

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Please see P2.10.1.1_Attachment 2.xlsx on the OEB's RDS.

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Please see P2.10.1.1_Attachment 3.xlsx on the OEB's RDS.

Sampled Companies	Avg OM/Customer	Annual Data Values Sampled Companies					
			2022	2021	2020	2019	2018
		Customers					
		O&M					
		OM/Customer					
		Avg					
EGI		148.8	155.0	142.2	149.1		
			2022	2021	2020		
Apex		Customers	82888	82043	81614		
		O&M	44505	44036	44349		
	539.0	OM/Customer	536.9	536.7	543.4		
			2022	2021	2020		
Atco		Customers	1279439	1263916	1247381		
		O&M	488062	513826	464924		
	386.9	OM/Customer	381.5	406.5	372.7		
			2022	2021	2020		
Liberty		Customers	12468	12262	12111		
		O&M	13159	14068	16296		
	1182.8	OM/Customer	1055.4	1147.3	1345.6		
			2022	2021	2020		
		Customers	1,067,191	1057086	1044623		
Fortis BC		O&M	328,179,000	328,345,000	313,815,000		
	306.2	OM/Customer	307.5	310.6	300.4		
			2022	2021	2020	2019	2018
Centra		Customers	293256	290502	287314	284996	281990
		O&M			58700	46814	63080
	197.4	OM/Customer			204.3	164.3	223.7
			2022	2021	2020	2019	2018
Eastward		Customers		8483	8066	7681	7316
		O&M		10735634	9883877	7549906	7289868
	1158.0	OM/Customer		1265.5	1225.4	982.9	996.4
			2022	2021	2020		
PNG		Customers	17951	17945	17954		
		O&M	25017	23027	21113		
	1284.3	OM/Customer	1394	1283	1176		
			2022	2021	2020		
PNG(NE)		Customers	18822	18770	18772		
		O&M	12571	11601	10980		
	623.6	OM/Customer	668	618	585		

Company	Avg OM/Customer	Time Period
Apex Gas	539.0	2020-2022
Atco Gas	386.9	2020-2022
Liberty Utilities	1182.8	2020-2022
Fortis BC	306.2	2018-2019
Centra	197.4	2018-2020
Eastward	1158.0	2018-2020
PNG	1284.3	2020-2022
PNG(NE)	623.6	2020-2022
Sample Avg.	709.8	
EGI Distribution	148.8	
EGI all ops.	217.3	

Diff. EGI and Sample Avg Most recent Data

Distribution	-79.0%
All ops	-69.4%

Enbridge Gas Inc.
Calculation of Annual Base Rate Adjustment for Expensing Capitalized Indirect Overheads

Line No.	Particulars ($000s)	2025	2026	2027	2028
		(a)	(b)	(c)	(d)
	Rate Base Investment				
1	Capital Expenditures	(50,000)	(100,000)	(150,000)	(200,000)
2	Cumulative Capital Expenditures	(50,000)	(150,000)	(300,000)	(500,000)
3	Average Investment	(14,000)	(76,384)	(186,266)	(341,909)
	Revenue Requirement Calculation				
	Operating Expenses				
4	Operating and Maintenance Expenses	50,000	100,000	150,000	200,000
5	Depreciation Expense (1)	(427)	(2,379)	(5,856)	(10,858)
6	Total Operating Expenses (line 4 + line 5)	49,573	97,621	144,144	189,142
7	Required Return (2)	(839)	(4,647)	(11,331)	(20,800)
8	Total Operating Expenses and Return (line 6 + line 7)	48,734	92,974	132,813	168,342
	Income Taxes				
9	Income Taxes - Equity Return (3)	(174)	(964)	(2,350)	(4,314)
10	Income Taxes - Utility Timing Differences (4)	8,358	16,871	25,485	32,633
11	Total Income Taxes (line 9 + line 10)	8,184	15,907	23,135	28,319
12	Total Revenue Requirement (line 8 + line 11)	56,918	108,881	155,947	196,661
13	Base Rate Adjustment (5)	56,918	51,963	47,066	40,713

Notes:
(1) Depreciation expense of 3.05% based on effective rates, as per EB-2022-0200, Draft Rate Order, Working Papers, Schedule 6 , p. 3.
(2) The Required Return assumes a capital structure of 62% Long-Term Debt at 4.17% and 38% common equity at the 2024 OEB-Approved return on equity of 9.21%. The annual Required Return is calculated as:
Average Investment (line 3) * 62% * 4.17% plus Average Investment (line 3) * 38% * 9.21%.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to CCA based of effective Rate of 7.47%.
(5) Base rate adjustment calculated as the difference between the prior year and current year revenue requirement.

Enbridge Gas Inc.
Allocation of Annual Base Rate Adjustment for Expensing Capitalized Indirect Overheads

Line No.	Particulars	Total O&M Expense Excluding Cost of Gas Allocation Factor (1) ($000s)	(%)	Base Rate Adjustment (3) 2025 ($000s)	2026 ($000s)	2027 ($000s)	2028 ($000s)
		(a)	(b)	(c)	(d)	(e)	(f)
	Union South Rate Zone						
1	Rate M1	190,362	22.4%	12,722	11,614	10,520	9,100
2	Rate M2	20,245	2.4%	1,353	1,235	1,119	968
3	Rate M4 (F)	7,188	0.8%	480	439	397	344
4	Rate M4 (I)	-	-	-	-	-	-
5	Rate M5 (F)	738	0.1%	49	45	41	35
6	Rate M5 (I)	7,802	0.9%	521	476	431	373
7	Rate M7 (F)	2,174	0.3%	145	133	120	104
8	Rate M7 (I)	131	0.0%	9	8	7	6
9	Rate M9	234	0.0%	16	14	13	11
10	Rate T1 (F)	5,163	0.6%	345	315	285	247
11	Rate T1 (I)	470	0.1%	31	29	26	22
12	Rate T2 (F)	12,792	1.5%	855	780	707	612
13	Rate T2 (I)	1,447	0.2%	97	88	80	69
14	Rate T3	1,412	0.2%	94	86	78	67
15	Total Union South Rate Zone	250,157	29.4%	16,718	15,263	13,824	11,958
	Union Ex-Franchise						
16	Rate C1 (F)	257	0.0%	17	16	14	12
17	Rate C1 (I)	579	0.1%	39	35	32	28
18	Rate M12	32,630	3.8%	2,181	1,991	1,803	1,560
19	Rate M13	104	0.0%	7	6	6	5
20	Rate M16	118	0.0%	8	7	7	6
21	Rate M17	24 (2)	0.0%	2	1	1	1
22	Total Union Ex-Franchise	33,712	4.0%	2,253	2,057	1,863	1,612
	Union North Rate Zone						
23	Rate 01	75,857	8.9%	5,070	4,628	4,192	3,626
24	Rate 10	7,566	0.9%	506	462	418	362
25	Rate 20	6,477	0.8%	433	395	358	310
26	Rate 25	2,250	0.3%	150	137	124	108
27	Rate 100	6,483	0.8%	433	396	358	310
28	Total Union North Rate Zone	98,634	11.6%	6,592	6,018	5,451	4,715
29	Total Union Rate Zone (line 15 + line 22 + line 28)	382,503	44.9%	25,563	23,337	21,138	18,285
	EGD Rate Zone						
30	Rate 1	316,889	37.2%	21,178	19,334	17,512	15,148
31	Rate 6	125,785	14.8%	8,406	7,674	6,951	6,013
32	Rate 100	-	-	-	-	-	-
33	Rate 110	9,679	1.1%	647	591	535	463
34	Rate 115	3,580	0.4%	239	218	198	171
35	Rate 125	4,614	0.5%	308	282	255	221
36	Rate 135	1,111	0.1%	74	68	61	53
37	Rate 145	2,908	0.3%	194	177	161	139
38	Rate 170	3,580	0.4%	239	218	198	171
39	Rate 200	883	0.1%	59	54	49	42
40	Rate 331	-	-	-	-	-	-
41	Rate 332	150	0.0%	10	9	8	7
42	Rate 401	-	-	-	-	-	-
43	Total EGD Rate Zone	469,179	55.1%	31,356	28,625	25,928	22,428
44	TOTAL Enbridge Gas Inc. (line 29 + line 43)	851,682	100.0%	56,918	51,963	47,066	40,713

Notes:
(1) Union Rate Zone as per EB-2011-0210, Exhibit G3, Tab 5, Schedule 1, pp. 22-24, updated.
EGD Rate Zone as per EB-2017-0086, Exhibit G2, Tab 5, Schedule 3, p. 1, updated.
(2) EB-2019-0183, Decision and Order, dated April 9, 2020, pp. 29-30.
(3) Allocated in proportion to column (a).