SECTION 1:
EXECUTIVE SUMMARY

Concentric Energy Advisors, Inc. ("Concentric") was retained to prepare this independent report as to the reasonableness of the capital structure currently authorized by the Ontario Energy Board ("OEB") for Enbridge Gas Inc. ("Enbridge Gas," "EGI," or the "Company"). Enbridge Gas' next rate application will cover the five-year period from 2024 to 2028.

Concentric followed the OEB's preferred approach to assessing capital structure for the utilities it regulates by beginning with a detailed risk analysis of Enbridge Gas, and specifically studying changes in Enbridge Gas' risk profile relative to the time when the OEB previously assessed the Company's capital structure. Enbridge Gas represents the amalgamation of Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union Gas"). Therefore, our analysis compares the Company's risk profile today to the Company's risk profile in 2012, which is the approximate period in which EB-2011-0354 (i.e., the OEB's most recent equity thickness evaluation for EGD) and EB-2011-0210 (i.e., the OEB's most recent equity thickness evaluation for Union Gas) occurred.

In our assessment, Enbridge Gas' risk profile has increased significantly as compared to its risk profile at the time of EB-2011-0354 and EB-2011-0210. The most material factor contributing to the increase is the Energy Transition – a broad-scale transformation from a primary reliance on fossil fuels to a primary reliance on more renewable fuel sources. Investors perceive the Energy Transition as transforming the long-term risk environment for local gas distributors such as the Company. Moody's Investor Service ("Moody's") has opined that "[l]ong-term challenges to natural gas infrastructure are increasing" and that "carbon reduction commitments raise operating risks and cost of capital."[1] Wells Fargo stated that this represents "a stark change from 5+ years ago when LDCs were considered to offer more sustainable growth at a lower risk profile."[2]

Despite these challenges, the Company is actively positioning itself to mitigate the effects of the Energy Transition, and we expect the Company and the OEB will work together to minimize, to the extent possible, the risks it presents, while simultaneously protecting customers' interests. However, we conclude that the Energy Transition makes the Company's business significantly riskier today than it was in 2012 from an investor's perspective.

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1 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.

2 Wells Fargo Securities, "Gas Utility 2021 Outlook," January 6, 2021, at 3.

We also find that there have been changes in other aspects of the Company's risk profile since 2012. In total, our study encompassed five primary aspects of the Company's risk profile: (1) Energy Transition risk, (2) Volumetric risk, (3) Financial risk, (4) Operational risk, and (5) Regulatory risk. Figure 1 summarizes the significant developments in each of these areas since EB-2011-0354 and EB-2011-0210, as well as our conclusions with respect to each risk area. We also examined independent market indicators regarding the riskiness of Canadian utility and gas utility investments, such as valuation multiples, Beta coefficients, and credit ratings. These indicators support our conclusion that the Company faces greater risk today than it did in 2012.

Figure 1: Risk Analysis Summary

Risk Category	Summary of Developments	Conclusion
Energy Transition	The Energy Transition began in earnest in the last five years. As investors and rating agencies widely recognize, it substantially affects the risk profile of North American gas distribution utilities, including Enbridge Gas.	**Significant Increase**
Volumetric	A weaker economic outlook, the introduction of competition from alternative gas suppliers, and increased competition from electricity (i.e., the Energy Transition) have combined to increase the Company's volumetric risk relative to EGI's previous equity thickness proceedings. Regulatory mechanisms provide short-term insulation, but do not change the long-term challenges facing the Company.	**Modest Increase**
Financial	EGI has experienced a gradual weakening in its debt-related credit metrics since 2012, and its credit profile is comparatively weak relative to the proxy group companies. The Company's credit spreads on debt issuances have widened slightly since 2012.	**Modest Increase**
Operational	The complexities of operating the utility have increased, putting pressure on the Company regarding project permitting, execution, and cost recovery. Successful management of the associated rate impacts depends on supportive regulation by the OEB and active management of changing asset life cycles through depreciation practices.	**Neutral to Modest Increase**
Regulatory	Straight-fixed-variable ("SFV") rate design reduces cost recovery risk, and the OEB's findings in EGI's Integrated Resource Planning ("IRP") proceeding provide a pathway for rate base treatment of IRP alternatives.	**Modest Decrease** *(Assuming SFV Approval)*

In accordance with OEB precedent, after determining that the Company's risk profile has significantly changed since 2012, we next developed an analysis of the appropriate equity ratio based on the Fair Return Standard ("FRS"). The FRS includes three components, none of which rank in priority to the

Regarding capital structure specifically, the OEB's policy is to only re-evaluate a utility's deemed equity ratio in the event that its risk profile changes significantly. Specifically, in the 2009 Cost of Capital Report, the OEB found:

> *The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk.*[11]

Concentric recognizes that the OEB has previously determined that the capital structure for a regulated utility will not be changed unless there is a demonstration that the utility's risk profile has materially changed since the previous review. However, this is not the standard used by investors to evaluate whether the authorized return (both ROE and capital structure) meets their return requirements. The comparable return standard also requires an analysis between the utility for which the return is being set and a peer group of companies with comparable risk. That is the purpose for establishing a risk-comparable proxy group. In our view, comparing changes in risk for the subject company over time does not provide a complete analysis of whether the capital structure remains appropriate. Despite this, we have developed the analysis in this report to address the OEB's two-stage test.

The OEB's Approach to Setting Equity Thickness for Enbridge Gas/Union Gas

The OEB's approach to setting capital structure in Ontario has evolved through a number of proceedings for both gas and electric distribution utilities. The OEB issues a generic ROE applicable to all utilities under its jurisdiction and generally accounts for the differences in risk among the individual utilities by adjusting their capital structures.

EGD's equity thickness was set at 35 percent in 1993. In 1997, the OEB published guidelines for its cost of capital methodology for gas distribution utilities. In the OEB's Draft Guidelines, it stated: "The Board's guidelines [assume] that the base capital structure will remain relatively constant over time and that a full reassessment of [the Company's] capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk."[14]

In 2006, EGD requested an increase in equity thickness from 35 to 38 percent. The OEB noted the trend among Canadian regulators towards thicker equity for utilities, and that EGD's equity percentage may have fallen out of line with its peers. However, since the OEB had recently allowed

11 *Id.*, at 50.

distributors;[16]

- For electricity transmitters, generators, and gas utilities, the equity thickness is determined on a case-by-case basis;[17]

The OEB also provided findings regarding the appropriate time frame over which it would perform its risk assessment, finding that the time frame began with "the time the issue was previously decided in EB-2006-0034."[18] In terms of forward-looking risks, the OEB found that "the relevant future risks are those that are likely to affect Enbridge in the near term," and that "[i]n considering the risk of future events, the Board will take into account the fact that, generally, the more distant the potential event, the more speculative is any conclusion on the likelihood that the risk will materialize."[19]

In terms of business risks faced by EGD, the OEB found that, compared to 2007, Enbridge had not experienced a significant increase in risk related to declining volumes, system size and complexity, or environmental and technological advancement. Regarding environmental and technological advancement risk, the OEB found "[t]he evidence does not demonstrate a tangible risk that new environmental policy and laws in relation to gas distribution will be implemented over the near term, or if implemented, will be likely to have a detrimental effect on Enbridge in terms of volume over the near term."[20]

EB-2017-0306 (EGD-Union Gas Amalgamation)

In its amalgamation application, EGD and Union proposed to maintain the equity ratio of the amalgamated entity at 36 percent, which was accepted by the OEB.

16 EB-2011-0354, Decision on Equity Ratio and Order, February 7, 2013, at 3.
17 *Ibid*.
18 *Id*., at 7.
19 *Ibid*.
20 *Id*., at 15.

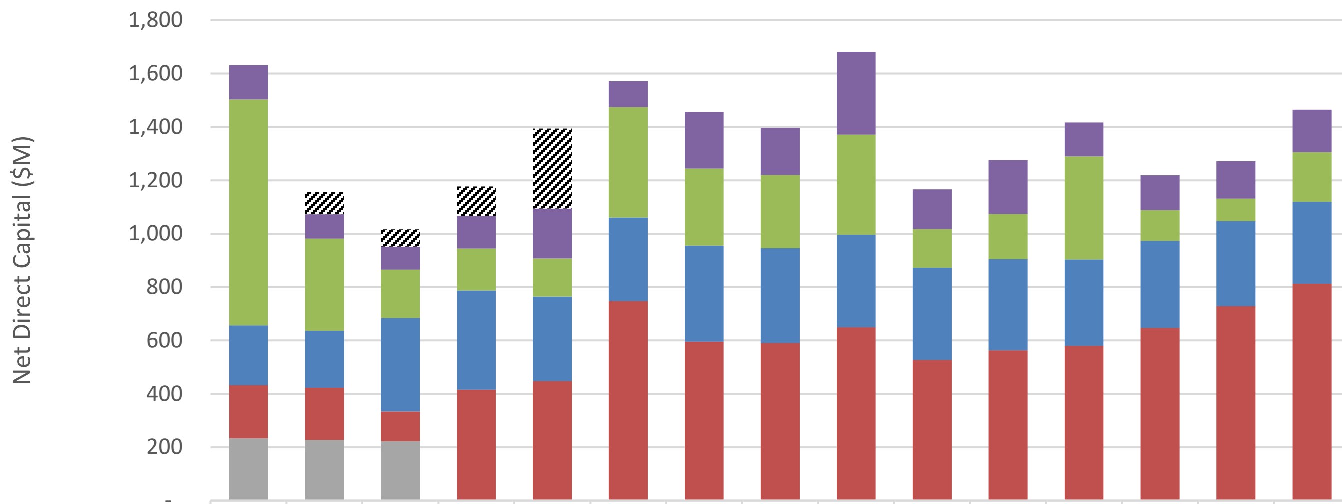
Table 1
Utility Rate Base & Capital Expenditures

Line No.	Particulars ($ millions)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Gross Property, Plant and Equipment	EGD	6,749.4	6,749.3	7,216.6	7,586.9	8,588.4	9,228.8	9,594.5
2	Accumulated Depreciation	EGD	(2,804.1)	(2,755.9)	(2,900.8)	(2,980.8)	(3,017.4)	(3,126.5)	(3,277.9)
3	Net Property, Plant and Equipment	EGD	3,945.3	3,993.4	4,315.8	4,606.1	5,571.0	6,102.3	6,316.6
4	Working Capital	EGD	216.7	299.8	385.5	473.7	338.0	362.9	412.6
5	Utility Rate Base	EGD	4,162.0	4,293.2	4,701.3	5,079.8	5,909.0	6,465.2	6,729.2
6	Capital Expenditures	EGD	449.9	517.8	612.3	1,015.4	593.9	431.4	413.3
7	Gross Property, Plant and Equipment	Union	6,361.5	6,401.2	6,674.3	7,029.5	7,683.0	8,628.2	9,398.6
8	Accumulated Depreciation	Union	(2,754.1)	(2,746.2)	(2,868.9)	(2,994.8)	(3,149.2)	(3,347.5)	(3,524.2)
9	Net Property, Plant and Equipment	Union	3,607.5	3,655.0	3,805.3	4,034.7	4,533.8	5,280.7	5,874.4
10	Working Capital	Union	196.8	198.2	225.8	235.5	254.1	210.5	148.5
11	Accumulated Deferred Income Taxes	Union	(69.7)	(69.3)	(54.7)	(41.8)	(29.5)	(17.3)	(4.5)
12	Utility Rate Base	Union	3,734.5	3,783.9	3,976.4	4,228.4	4,758.4	5,473.9	6,018.4
13	Capital Expenditures	Union	347.7	368.2	476.9	691.3	1,034.0	721.0	519.2
14	Total Utility Rate Base	Combined	7,896.5	8,077.1	8,677.7	9,308.2	10,667.4	11,939.1	12,747.6
15	Total Capital Expenditures	Combined	797.6	886.0	1,089.2	1,706.7	1,627.9	1,152.4	932.5

Table 2
Utility Rate Base & Capital Expenditures

Line No.	Particulars ($ millions)	Utility	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Estimate (d)	2023 Bridge Year (e)	2024 Test Year (f)
1	Gross Property, Plant and Equipment	EGI	19,765.5	20,582.1	21,539.8	22,663.3	23,880.2	24,922.9
2	Accumulated Depreciation	EGI	(7,188.7)	(7,571.2)	(8,005.9)	(8,517.0)	(9,027.6)	(9,296.7)
3	Net Property, Plant and Equipment	EGI	12,576.8	13,010.8	13,533.9	14,146.3	14,852.6	15,626.2
4	Allowance for Working Capital	EGI	562.3	551.2	687.7	855.9	689.6	558.1
5	Utility Rate Base	EGI	13,139.0	13,562.0	14,221.6	15,002.1	15,542.2	16,184.3
6	Capital Expenditures	EGI	1,087.4	1,007.4	1,310.8	1,444.3	1,625.8	1,491.7

Figure 7: Enbridge Gas's Capital Expenditure Summary (with proposed ICM project in-service spend identified from 2019 – 2022)



	2018A	2019A	2020A	2021A	2022F	2023F	2024F	2025F	2026F	2027F	2028F	2029F	2030F	2031F	2032F
ICM Projects	-	84	66	111	299				-	-					
General Plant	128	91	85	122	188	96	213	176	311	149	202	127	130	139	159
System Service	848	345	182	157	142	414	289	274	375	145	169	386	115	84	186
System Access	224	213	350	371	317	313	360	355	346	345	342	324	326	319	307
System Renewal	199	196	111	416	448	747	595	591	650	528	562	580	647	728	812
Overhead	233	227	223	-		-	-	-	-	-					
Grand Total	1,631	1,157	1,017	1,177	1,394	1,571	1,457	1,397	1,682	1,166	1,275	1,417	1,219	1,271	1,464

Notes:

1. Overheads are included in USP categories starting in 2021

6. Continuous Improvements and Benchmarking

85. Enbridge Gas continues to seek opportunities to build continuous improvements into its planning processes, goals and objectives. Our strategic priorities guide decision making and continue to support streamlining our operations and optimizing our distribution, storage, and transmission assets. Examples of opportunities anticipated over the 2024 to 2028 IR term include organizational alignment within Enbridge Gas's regional construction teams, productivity gains in alliance partner

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 51 of 164

Question(s):

Concentric has stated the following on the referenced page:

> Figure 9 presents the normalized average use of natural gas by the Company's residential customers from 2006 to 2021. This figure shows that normalized residential average use has declined even further from 2012 levels. In fact, for the period 2006 to 2012, the average annual growth rate in residential average use was -0.30%. For the period 2013 to 2021, the average annual growth rate decreased to -0.57%.

a) As Concentric has compared Enbridge Gas's risk profile in 2022 to EGD and Union Gas's risk profile in 2012, please provide the following information starting from 2012 (in MS Excel format):

   i. Actual annual load/sales and consumer data from 2012 to 2022 (segregated by consumer category). Please ensure that the data is provided separately for EGD and Union Gas from 2012 to 2018.

   ii. Forecasted annual load/sales and consumer data from 2023 to 2028 (segregated by consumer category).

Response:

a) Please see Attachment 1 for the Excel, for the actual and forecast normalized volumes based on 2024 Test Year weather normalization by sector from 2012 to 2028. Please see Attachment 2 for the Excel, for the actual and forecast average customer count by sector from 2012 to 2028.

Attachment 1

Actual and Forecast Normalized Volumes Based on 2024 Test Year Weather Normalization (By Sector)

Line No.	Particulars (10^3m^3)	Utility	2012 Actual (a)	2013 Actual (b)	2014 Actual (c)	2015 Actual (d)	2016 Actual (e)	2017 Actual (f)	2018 Actual (g)
	General Service (1)								
1	Residential	EGD	4,609,025	4,640,235	4,707,031	4,684,212	4,688,730	4,851,455	4,871,656
2	Commercial	EGD	3,955,153	3,966,684	4,118,739	4,083,781	3,940,052	4,120,966	4,383,105
3	Industrial	EGD	661,940	641,752	671,610	657,196	638,905	641,496	654,638
4	Total - EGD Rate Zone		9,226,118	9,248,671	9,497,379	9,425,189	9,267,686	9,613,916	9,909,398
5	Residential	Union	2,867,333	2,904,206	2,950,616	2,895,911	2,914,430	3,018,534	3,059,253
6	Commercial	Union	1,917,736	1,954,410	2,026,199	1,996,427	1,991,921	2,062,169	2,074,923
7	Industrial	Union	481,603	483,636	482,106	493,667	478,332	499,758	509,834
8	Total - Union Rate Zone		5,266,671	5,342,252	5,458,921	5,386,005	5,384,683	5,580,461	5,644,011
9	Total General Service		14,492,790	14,590,922	14,956,300	14,811,194	14,652,370	15,194,377	15,553,408
	Contract								
10	Contract	EGD	2,056,400	2,022,700	1,922,500	1,913,500	1,935,100	1,910,800	1,971,300
11	Contract	Union	9,135,278	8,996,029	8,701,465	8,318,496	8,169,694	7,383,273	7,844,060
12	Total Contract		11,191,678	11,018,729	10,623,965	10,231,996	10,104,794	9,294,073	9,815,360
13	Total Volumes		25,684,468	25,609,651	25,580,265	25,043,190	24,757,164	24,488,450	25,368,768

Notes:

(1) Volumes normalized to 2024 Test Year Forecast heating degree days.

Attachment 1
Actual and Forecast Normalized Volumes Based on 2024 Test Year Weather Normalization (By Sector)

Line No.	Particulars (10^3m^3)	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	General Service (1)										
1	Residential	8,034,144	8,166,924	8,044,339	8,040,778	8,149,365	8,179,258	8,209,652	8,234,539	8,260,731	8,284,447
2	Commercial	6,436,062	6,289,129	6,069,543	6,224,539	6,441,180	6,448,091	6,429,395	6,408,538	6,389,423	6,370,410
3	Industrial	1,135,057	1,028,084	990,918	945,873	1,084,500	1,060,859	1,045,617	1,030,553	1,016,838	1,002,565
4	Total General Service	15,605,263	15,484,137	15,104,801	15,211,190	15,675,046	15,688,207	15,684,664	15,673,630	15,666,992	15,657,422
	Contract										
5	Total Contract	10,409,038	10,407,657	11,364,220	12,226,415	12,026,774	12,234,665	12,456,037	13,289,325	13,296,345	13,285,182
6	Total Volumes	26,014,301	25,891,794	26,469,020	27,437,604	27,701,820	27,922,873	28,140,701	28,962,955	28,963,338	28,942,604

Notes:
(1) Volumes normalized to 2024 Test Year Forecast heating degree days.

Attachment 2
Actual and Forecast Average Customer Count (By Sector)

Line No.	Particulars	Utility	2012 Actual (a)	2013 Actual (b)	2014 Actual (c)	2015 Actual (d)	2016 Actual (e)	2017 Actual (f)	2018 Actual (g)
	General Service								
1	Residential	EGD	1,836,267	1,869,325	1,901,207	1,930,657	1,959,569	1,990,032	2,017,128
2	Commercial	EGD	152,144	154,228	156,181	157,623	158,747	160,325	161,367
3	Industrial	EGD	6,063	6,039	6,056	6,017	5,951	5,902	5,851
4	Total - EGD Rate Zone		1,994,474	2,029,591	2,063,444	2,094,297	2,124,267	2,156,259	2,184,345
5	Residential	Union	1,250,461	1,269,050	1,287,709	1,306,495	1,325,703	1,344,513	1,364,322
6	Commercial	Union	111,557	112,508	113,652	114,594	115,340	115,973	116,727
7	Industrial	Union	5,391	5,365	5,353	5,305	5,271	5,261	5,244
8	Total - Union Rate Zone		1,367,409	1,386,924	1,406,714	1,426,394	1,446,314	1,465,747	1,486,293
9	Total General Service		3,361,883	3,416,514	3,470,158	3,520,691	3,570,581	3,622,006	3,670,639
	Contract								
10	Contract	EGD	429	412	394	384	416	409	414
11	Contract	Union	477	484	476	468	465	476	477
12	Total Contract		906	896	870	852	881	885	891
13	Total Customers		3,362,789	3,417,410	3,471,028	3,521,543	3,571,462	3,622,891	3,671,530

Attachment 2
Actual and Forecast Average Customer Count (By Sector)

Line No.	Particulars	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Actual (d)	2023 Forecast (e)	2024 Forecast (f)	2025 Forecast (g)	2026 Forecast (h)	2027 Forecast (i)	2028 Forecast (j)
	General Service										
1	Residential	3,424,068	3,463,393	3,501,050	3,537,833	3,577,066	3,613,542	3,650,187	3,684,193	3,718,253	3,750,689
2	Commercial	280,104	281,892	283,411	283,141	286,523	289,171	290,757	292,267	293,829	295,299
3	Industrial	10,996	10,987	10,960	11,070	10,918	10,971	10,939	10,921	10,921	10,915
4	Total General Service	3,715,168	3,756,272	3,795,420	3,832,044	3,874,507	3,913,684	3,951,883	3,987,380	4,023,004	4,056,903
	Contract										
5	Total Contract	905	969	1,036	1,067	1,030	1,028	1,029	1,029	1,029	1,029
6	Total Customers	3,716,073	3,757,241	3,796,456	3,833,111	3,875,537	3,914,712	3,952,911	3,988,409	4,024,032	4,057,931

SECTION 4(a):
ENERGY TRANSITION

Introduction

In EB-2011-0354, EGD stated that it faced increased business risk due to environmental policies and laws such as Ontario's Green Energy Act (2009). EGD further submitted that there "is a clear long-term risk that demand for natural gas will decline, as new technologies and energy saving practices take further hold."[22] However, the OEB concluded in 2013 that "Enbridge has not experienced a significant increase in risk since 2007 relating to environmental and technological advancement."[23] Specifically, the OEB found:

> *The evidence does not demonstrate a tangible risk that new environmental policy and laws in relation to gas distribution will be implemented over the near term, or if implemented, will be likely to have a detrimental effect on Enbridge in terms of volume over the near term. The Board agrees with intervenors that, to the contrary, the policy commitment to cease all coal-fired electricity generation in Ontario is likely to result in more gas-fired electricity generation, which is a benefit to Enbridge. In addition, as discussed under Volumetric Demand Profile, to the extent that DSM initiatives decrease Enbridge's volume, this risk is addressed by the LRAM account. Also, as discussed above, increasing energy efficiency has the effect of strengthening the ongoing competitive position of gas compared to other fuels.*[24]

The situation today is starkly different than at the time of the OEB's above-quoted findings. Within the last five years, and accelerating within the past year, the global energy sector has embarked on a broad-scale transformation, referred to generally as the "Energy Transition," from a primary reliance on fossil fuels to an increased emphasis on more renewable fuel sources.[25] As a result, the risk profile of natural gas distribution utilities such as Enbridge Gas has fundamentally changed.

The subsections that follow discuss the evidence that the Energy Transition is already underway, the steps the Company has taken in response to the Energy Transition, and the effects of the Energy Transition on the Company's current risk profile.

22 EB-2011-0354, Ontario Energy Board Decision on Equity Ratio and Order, February 7, 2013, at 14.
23 *Id.*, at 15.
24 *Ibid.*
25 S&P Global, "What is Energy Transition," February 24, 2020, https://www.spglobal.com/en/research-insights/articles/what-is-energy-transition.

> *of lower-carbon alternatives to natural gas, as happened with renewables in the electricity sector. The transition is already underway: at the current rate, the number of homes with electric space heating could exceed the number of homes with gas space heating by 2032.*[35]

Concentric is not aware of any building gas bans, or prohibitions on such bans, in Ontario. However, as discussed previously, 48 municipalities have already declared climate emergencies in Ontario. Twenty one Ontario communities, including the City of Toronto, are urging the Ontario government to phase out the use of gas-fired electricity generation.[36] In December 2021, the Toronto City Council adopted an ambitious strategy to reduce community wide GHG emission in Toronto to net zero by 2040 – ten years earlier than initially proposed. Toronto's net zero by 2040 target is one of the most ambitious in North America. To reach its targets, the City will use its influence to regulate, advocate and facilitate transformation in five key areas:

- Demonstrate carbon accountability locally and globally, by establishing a carbon budget for its own operations and the community as a whole.
- Accelerate a rapid and significant reduction in natural gas use.
- Establish performance targets for existing buildings across Toronto.
- Increase access to low-carbon transportation options, including walking, biking, public transit and electric vehicles.
- Increase local renewable energy to contribute to a resilient, carbon-free grid.[37]

Further, while not enacted, the provincial government has previously drafted climate change action plans that include the phase-out of gas for home heating by 2030.[38] Additionally, the current Minister of Energy, Todd Smith, requested in 2021 that the Independent Electricity System Operator ("IESO") (1) "evaluate a moratorium on the procurement of new natural gas generating stations in Ontario," and (2) "develop an achievable pathway to phase-out natural gas generation and achieve zero emissions in the electricity system."[39] Then, in August 2022, Mr. Smith accelerated the timeline for an interim report from the IESO, stating that he "asked the IESO to speed up that report back to us so

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35 The Brattle Group, "The Future of Gas Utilities Series: Transition Gas Utilities to A Decarbonized Future," Part 1 of 3, August 2021, at 9.

36 The Energy Mix, "Toronto City Council Calls for Ontario Gas Phaseout," March 12, 2021, https://www.theenergymix.com/2021/03/12/toronto-city-council-calls-for-ontario-gas-phaseout/.

37 https://www.toronto.ca/news/net-zero-by-2040-city-council-adopts-ambitious-climate-strategy/

38 CBC News, "Ontario Government Not Denying Report on Sweeping Climate Change Plan," March 12, 2021, https://www.theenergymix.com/2021/03/12/toronto-city-council-calls-for-ontario-gas-phaseout/.

39 Letter from the Honourable Todd Smith, Minister of Energy, to Lesley Gallinger, President and Chief Executive Officer of the Independent Electricity System Operator, October 7, 2021.

Decarbonization and Ontario's Electricity System

Assessing the impacts of phasing out natural gas generation by 2030

OCTOBER 7, 2021

ieso
Connecting Today.
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PUBLIC

Introduction

Ontario homeowners, businesses, and organizations across many sectors, including municipalities, are actively pursuing new opportunities to accelerate decarbonization. With one of the cleanest power grids in North America, Ontario is at a considerable advantage to decarbonize its economy through electrification.

Less than a decade ago, Ontario's electricity system made a seismic shift with the elimination of coal generation. Today it is 94 per cent emissions-free and contributes only three per cent to the province's total greenhouse gas emissions – with nuclear power supplying the bulk of our energy needs and natural gas generation working to support wind and solar power.

Yet, with emissions from gas generation forecast to increase in the next few years, some Ontarians are asking whether the electricity sector can do more to support decarbonization goals by further reducing its carbon footprint.

The IESO is listening. As the power system operator and planner, we understand the evolving challenges and opportunities in the electricity sector, and are uniquely positioned to inform this discussion.

This study, therefore, examines the question posed by more than 30 Ontario municipal councils in their resolutions calling for the complete phase out of natural gas generation in the province by 2030. We have used our expertise to produce a technical assessment that explores, at a high level, the impacts to power system cost and reliability in removing carbon emissions from the system.

Our study shows that natural gas generation provides a level of flexibility to respond to changing system needs that would be impossible to replace in the span of just eight years. As a highly flexible resource, gas delivers energy when it is needed most, providing almost three quarters of the system's ability to respond quickly to changes in demand. Newer forms of supply, such as energy storage, are not ready to operate at the scale that would be needed to compensate; nor is there enough time or resources to build the necessary generation and transmission infrastructure to replace gas generation within an eight-year timeframe.

Even if these practical considerations could be overcome, the most optimistic assumptions show that without gas generation, Ontario's electricity system would see frequent and sustained blackouts in 2030. As evidenced by the recent blackouts in California, there is a considerable risk in not having a diverse supply mix effectively balanced against the variability of solar and wind output.

In addition, the analysis shows that removing gas from the electricity system would result in a substantial increase in costs to consumers. For the average homeowner, the effect of removing gas would add $100 to the monthly electricity bill, which represents a 60 per cent increase. Rising costs would also stifle investments in decarbonization.

These results, however, are only one part of the broader picture of emissions in Ontario. The study also identifies the work that needs to be done to ensure the system supports demand growth from electrification and at the same time mitigates its own emissions.

While the removal of gas from the grid is not possible by 2030, it can be accomplished in a way that will ensure reliability, given an adequate amount of time for the sector to plan and prepare.

Properly assessing this kind of work will be critical – and can't be done in isolation. Just as this study was informed by input from stakeholders and community feedback, the IESO will continue working within the sector – as well as with businesses, academics, municipalities and other organizations in the broader electrification space – to explore the best approach to leverage the electricity sector to support decarbonization in Ontario.

d) *Regulatory Response*

In response to these developments, multiple regulators in the U.S. have opened dockets investigating the role that local gas distribution companies ("LDCs") will play during and after the Energy Transition. For example, in Massachusetts, the Office of the Attorney General ("AGO") petitioned the Department of Public Utilities ("DPU") in June 2020 to "initiate an investigation to assess the future of LDC operations and planning in light of the Commonwealth's legally binding statewide limit of net-zero greenhouse gas ('GHG') emissions by 2050."[51] The AGO acknowledged that "climate policy requirements will have profound impacts on gas distribution system management, operations, and rates. This will require the LDCs to make significant changes to their planning processes and business model."[52] Noting that as "electrification and decarbonization of heating increases, the Commonwealth's natural gas demand and usage from thermal heating requirements will decline substantially and could be near zero by 2050,"[53] the AGO raised several questions, including:

- "Should shareholders pay for the diversification and expansion of the LDC's business operations to meet GHG emission limits?"[54]
- "How much additional LDC investment is prudent in the next 30 years to ensure a safe and reliable gas distribution system, while statewide gas demand declines?"[55]
- "Should the Department [i.e., the DPU,] adjust GSEP [Gas System Enhancement Plan] planning and cost recovery to mitigate against potentially stranded infrastructure investment, as well as operations and maintenance expenses as a result of declining gas demand? Should accelerated depreciation or retirement of older leak prone infrastructure alternatives be considered?"[56]
- "Can the LDCs sustain their current business model as the Commonwealth takes affirmative action to electrify and decarbonize the heating sector? What does the LDC look like in 2030? 2040? 2050?"[57]

Additionally, the Public Utilities Commission of the State of Colorado ("Colorado PUC") opened a proceeding in 2020 to "serve as a repository for presentations, comments, and other materials

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51 Massachusetts Docket D.P.U. 20-80, Petition of the Office of the Attorney General, June 4, 2020, at 1.
52 *Id*., at 2.
53 *Id*., at 7.
54 *Id*., at 12.
55 *Id*., at 13.
56 *Id*., at 14.
57 *Id*., at 15-16.

about the distribution system questions before the -- neither the electric nor gas distribution system being, you know, reflected in that study. So there are clearly other things you would want to bring in, to get a comprehensive picture of, you know, what is going on across that transition.

MR. YAUCH: Thank you. So if we can go to the page 7 of the evidence, the next page? So the fourth paragraph, you recommend that:

"Enbridge be required to complete a detailed business analysis following the publication of Ontario's pathway study and the conclusion of the electrification energy transition panel."

The recommendation is based on the reality that, as far as we can tell, that there is little certainty regarding the energy transition and how it is going to play out today, that we don't actually know what the provincial policy is. Correct?

DR. HOPKINS: Right. I just, for the help of the screen --

MR. YAUCH: Yes.

DR. HOPKINS: -- I think we are on page 6, on the fourth bullet.

Yes. Yes, the range of possible pathways for Ontario is wide at the moment. I recommended doing analysis, you know, closely after and informed by the province's process, because that will, I would hope and assume, narrow that spread somewhat, or provide some sense of the weighting of different scenarios one might apply et cetera.

But yes, you know, I think it is fair to say that there is more uncertainty now, and will be less uncertainty after that process is complete. Even that won't fully settle everything, I am sure.

MR. YAUCH: In your view, is it imprudent to be making significant decisions on the future of the gas delivery system today, without that certainty?

DR. HOPKINS: Well, I think imprudent being a -- I think being very careful --

MR. YAUCH: It is a loaded term, I know.

DR. HOPKINS: Yes. You know, I think it, you know, the right thing to do is use the best information you have at the time that you have to make a decision. Right? In some cases, the right thing to do is to wait on making a decision until you have better information and, in some cases you need -- you know, acting or not acting, either one is a decision. Right?

And yet you may be, you know, forced to make a decision, you know, at a given time. And did you use the best information you have, the best modelling that is available to you and the best, you know -- to try to make the most prudent decision you can, in that context.

MR. YAUCH: Thank you. If you can go to page 38 of the Evidence? Actually, page 39, sorry. So here, you note that:

"Neither of the studies filed in this proceeding undertook a detailed review of Enbridge's

> *recover those costs from a shrinking customer base. This puts remaining customers at risk, a "death spiral" trend pushing more customers to electrification. Up to $150–180 billion of gas distribution assets could be underrecovered as a result of the transition. This spiral will increase customer costs and increase energy burdens, especially for low-income and vulnerable populations.*[97]

Brattle also observes that the "transition will not occur at the same pace or magnitude across customer classes, which compounds cost recovery risks."[98]

Therefore, as discussed more fully in the volumetric risk section below, we conclude that the Energy Transition increases the Company's volumetric risk.

b) Operational Risk

Increasing opposition to natural gas makes it more difficult, costly, and time-intensive for natural gas distribution utilities such as the Company to construct and permit new facilities. Depending on the extent of this opposition, shareholders may bear increasing amounts of operational risks or cost overruns as critical infrastructure projects are delayed. As Moody's notes:

> *Long-term challenges to natural gas infrastructure are increasing. Natural gas is increasingly being called into question over environmental and greenhouse gas (GHG) emissions. Permitting difficulties related to new pipelines, local government mandates favoring electrification and state carbon reduction commitments raise operating risks and cost of capital.*[99]

This increasing opposition represents a marked change from the operating environment in 2012 (i.e., the Company's previous equity thickness proceedings). In 2020, the New York Times noted that oil and gas pipelines are "being challenged as never before as protests spread, economics shift, environmentalists mount increasingly sophisticated legal attacks and more states seek to reduce their use of fossil fuels to address climate change."[100] Setbacks experienced by the Atlantic Coast Pipeline, the Dakota Access Pipeline, and the Keystone XL oil pipeline were specifically cited as evidence that heightened opposition "represents a break from the past decade, when energy companies laid down tens of thousands of miles of new pipelines."[101] It was further noted that, even

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97 Brattle, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 11.
98 *Id.*, at 15.
99 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.
100 New York Times, "Is This the End of New Pipelines?" July 8, 2020, https://www.nytimes.com/2020/07/08/climate/dakota-access-keystone-atlantic-pipelines.html.
101 *Ibid*.

Project,[116] respectively. Intervenors have challenged those projects, in part, on concerns about long-lived assets becoming stranded because of the declining use of fossil fuels, including natural gas.[117]

The above-referenced leave to construct applications are individual data points and do not represent a comprehensive review of all of the Company's filings since 2012. However, they do serve as case studies illustrating that the Company's experience is consistent with the broader natural gas industry. Thus, we conclude that the Energy Transition has significantly increased the Company's operational risk by increasing the possibility that it will face challenges and delays in siting, permitting, and constructing facilities.

c) Stranded Asset Risk

Another risk of the Energy Transition is that a significant portion of the Company's gas plant investments could become stranded. Generally, the term "stranded asset" refers to an investment that becomes no longer used or useful in the provision of service to customers before the end of its depreciable life. At that point in time, the undepreciated value of the asset (i.e., its net book value) is "stranded" with costs to be borne by either investors or customers. Gas distribution utilities such as the Company generally depreciate capital invested in their systems over the expected useful life of the underlying physical property, which is often many decades. Therefore, the Energy Transition creates stranded asset risk for the Company by introducing the possibility that significant portions of the Company's property will cease being used or useful before it is fully depreciated. In fact, the OEB recently acknowledged the risk of stranded assets when evaluating the Company's IRP proposal.[118]

The potential for stranded assets was not a material concern for the Company in 2012 (i.e., the time of its previous equity thickness proceedings). As S&P notes, "[s]tranded costs have not up until now been an issue for gas local distribution companies."[119] S&P observes, however, that concerns about stranded assets have spiked recently:

> *While new pipelines have faced fierce opposition from environmental activists and local communities since the initial shale gas development boom and the pace of new projects*

[116] EB-2022-0157.
[117] See, e.g., EB-2022-0088, Pollution Probe Submission, September 23, 2022, at 4; and Environmental Defence Submission, at 2-3. See also, e.g., EB-2022-0157, Interrogatories of Environmental Defence (September 1, 2022), at 4-6.
[118] EB-2020-0091, Decision and Order, July 22, 2021, at 62.
[119] S&P Global Market Intelligence, "RRA Regulatory Focus: 2021 Energy Utility Regulatory Focus," February 11, 2021, at 10.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 46 of 164

Question(s):

Concentric has stated the following on the referenced page: "Another risk of the Energy Transition is that a significant portion of the Company's gas plant investments could become stranded."

Please provide specific examples of the OEB failing to provide cost recovery for stranded assets in the last 10 years.

Response:

The following response was provided by Concentric Energy Advisors, Inc.:

Concentric is not aware of any cases in the last 10 years where the OEB failed to provide cost recovery for stranded assets. Concentric is also unaware of cases where the OEB has been asked to rule on that question in any recent case. As noted by the OEB in EB-2020-0091, "[t]he OEB has limited experience with the treatment of stranded assets." (EB-2020-0091, Decision and Order, July 22, 2021, at 62).

changing where supply is coming in, where demand is, and how the system flows, as well as introducing hydrogen into the system. Changing the way the distribution system works relative to how it was originally designed has risks in and of itself. All of these factors increase the uncertainty and risk of operating the gas distribution system as compared to the situation in 2012.

Amalgamation of EGD and Union Gas

The amalgamation of EGD and Union Gas was effective on January 1, 2019. While the resulting combined gas utility now serves more than 3.8 million customers in Ontario and has higher revenues and annual throughput than in 2012, EGD was already one of the largest gas LDCs in North America in 2012 when the OEB set the deemed equity ratio at 36 percent. The amalgamation with Union Gas did not change that situation. However, S&P observes that the amalgamation with Union Gas did not increase the geographic, economic, or regulatory diversification of EGI. The Company remains wholly dependent on the economic and business environment in the Province of Ontario, as well as being dependent on the decisions of the OEB. In summary, the amalgamation of EGD and Union Gas did not reduce the operating risk profile of the resulting EGI as compared to EGD in 2012.

Conclusions

Our conclusion is that operational risk has increased for EGI compared with 2012. In particular, operational risk has increased in the following areas: 1) the Energy Transition and anti-carbon sentiment; 2) risks due to climate change and severe weather; 3) higher insurance costs; 4) safety requirements and cyber-security concerns; 4) and more stringent engineering regulations and greater operational complexity. While the Company has grown in size due to the amalgamation of EGD and Union Gas, this did not reduce the operating risk profile of the resulting EGI.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 6 of 164/Table 1

Question(s):

Exhibit 5/Tab 3/Schedule 1/Attachment 1 is the evidence of Concentric Energy Advisors, Inc. (Concentric), and is entitled *Enbridge Gas Inc. - Common Equity Ratio Study*, dated October 17, 2022 (Concentric Report). Table 1 of the Concentric Report, on page 6 of 164, is a “Risk Analysis Summary” of Concentric’s assessment of EGD’s / Enbridge Gas’s business, operational, financial, volumetric and regulatory risk since 2012, when the OEB last made a determination of EGD’s risk based on evidence in front of it in a rate application for the utility.[1]

OEB staff notes that Concentric does not identify the formation of Enbridge Gas Inc. as a result of an acquisition and amalgamation of Union Gas and EGD approved by the OEB in a joint MAADs and multi-year rate plan application,[2] as a major factor in any change in the risk since 2012.

a) All else being equal, would not investors and lenders consider that the amalgamation of EGD and Union Gas, and creating a larger utility with service areas (in the more populous area of southern Ontario) largely contiguous and thus offering opportunities for economies of scale and other synergies, as lowering the risk of Enbridge Gas relative to that of EGD as assessed in 2012?

b) Please explain why Concentric does not consider the amalgamation of EGD and Union Gas, upon acquisition of the latter, to form Enbridge Gas, a major change affecting Enbridge Gas’s business risk relative to that of EGD in 2012.

[1] EB-2011-0354 and EB-2011-0210.
[2] EB-2017-0306/-0307.

Response:

The following response was provided by Concentric Energy Advisors, Inc.:

a) While the amalgamation of EGD and Union Gas created a larger utility and resulted in economies of scale and synergies, investors and rating agencies already considered EGD and Union Gas to be large utilities prior to the amalgamation. The combined company, Enbridge Gas, does not have more economic or regulatory diversification than before the amalgamation. The business and financial risk profile of Enbridge Gas did not change in any meaningful way as a result of the amalgamation. The combined company continues to be regulated in the same manner by the OEB. Please see the response at Exhibit I.5.3-CME-46 for additional discussion.

b) Please see the response to part a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 17 of 164

Preamble:

Concentric's report states:
There are two fundamental sources of risk for any company, including regulated utilities: business risk and financial risk. Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including a fair return on, and of, its capital in a timely manner. These risks include operating risk and regulatory risk. Financial risk relates to a company's debt leverage and liquidity and is measured by its credit profile. Both business and financial risk have a direct bearing on a utility's cost of capital.

Question(s):

a) Please provide a table of EGI's (and for periods before the merger Enbridge Gas Distribution and Union Gas) allowed rate of return and return on equity and the actual rate of return and return on equity, for each year since 1990.

b) Please provide a table, as well as the accompanying worksheets, that reports the allowed return on equity and the actual return on equity for each of the companies included in the four proxy groups, for each year since (and including) 2012.

Response:

a) Please see Attachment 1. For the years prior to amalgamation, information is broken down between Enbridge Gas Distribution and Union. For years prior to 2007 the schedule notes a number of data points that Enbridge Gas was not able to find and provide in this response despite making reasonable efforts.

The following response was provided by Concentric Energy Advisors, Inc.:

b) Concentric has not compiled the allowed and actual ROEs for each of the operating companies in the four proxy groups. Not all regulated utilities report earned ROEs on an annual basis, and calculating earned ROEs from accounting data is complicated by the many common adjustments made for regulatory accounting purposes.

EGD Rate of Return and Return on Equity

Year	Actual Return on Common Equity ($ millions)	Allowed Return on Common Equity ($ millions)	Actual ROE % (1)	Allowed ROE %	Net Earnings (Deficiency)/ Sufficiency ($ millions)
1990	73.4	71.4	13.60%	13.25%	2.0
1991	77.5	76.5	13.29%	13.13%	1.0
1992	83.2	84.6	13.40%	13.13%	(1.4)
1993	89.8	89.1	14.43%	12.30%	0.7
1994	91.6	91.1	12.49%	11.60%	0.5
1995	98.8	99.1	12.66%	11.65%	(0.3)
1996	107.1	108.2	13.14%	11.88%	(1.1)
1997	111.7	114.0	13.00%	11.50%	(2.3)
1998	109.9	110.3	11.97%	10.30%	(0.4)
1999	106.4	109.3	10.77%	9.51%	(2.9)
2000	N/A	95.6	10.83%	9.73%	N/A
2001	N/A	104.1	10.03%	9.54%	N/A
2002	N/A	102.1	11.81%	9.66%	N/A
2003	109.4	107.0	9.94%	9.69%	2.4
2004	122.4	109.5	10.83%	9.69%	12.9
2005	N/A	114.6	10.34%	9.57%	N/A
2006	N/A	111.2	10.34%	8.74%	N/A
2007	127.7	113.1	9.78%	8.39%	14.6
2008	138.9	131.4	10.21%	9.66%	7.5
2009	153.0	127.2	11.20%	9.31%	25.8
2010	153.0	129.5	11.08%	9.37%	23.5
2011	147.8	127.4	10.38%	8.94%	20.4
2012	138.2	123.0	9.57%	8.52%	15.2
2013	161.0	138.1	10.41%	8.93%	22.9
2014	177.0	158.4	10.46%	9.36%	18.6
2015	179.6	170.1	9.82%	9.30%	9.5
2016	200.5	195.5	9.42%	9.19%	5.0
2017	238.9	204.3	10.27%	8.78%	34.6
2018	260.7	218.0	10.76%	9.00%	42.7

(1) based on normalized weather
N/A - Enbridge Gas was not able to find and provide in this response despite making reasonable effort

Union Rate of Return and Return on Equity

Year	Actual Return on Common Equity ($ millions)	Allowed Return on Common Equity ($ millions)	Actual ROE %	Allowed ROE %	Net Earnings (Deficiency)/ Sufficiency ($ millions)
1990	N/A	45.6	13.30%	13.75%	N/A
1991	49.85	50.3	10.70%	13.50%	(0.4)
1992	54.38	58.8	11.50%	13.50%	(4.5)
1993	64.92	61.8	14.00%	13.00%	3.2
1994	74.46	65.0	15.30%	12.50%	9.4
1995	N/A	69.3	12.17%	11.75%	N/A
1996	N/A	N/A	13.47%	11.75%	N/A
1997	N/A	83.9	12.19%	11.00%	N/A
1998	N/A	116.9	8.03%	10.44%	N/A
1999	N/A	N/A	8.76%	9.61%	N/A
2000	N/A	N/A	10.62%	9.95%	N/A
2001	N/A	N/A	9.30%	9.95%	N/A
2002	N/A	N/A	10.75%	9.95%	N/A
2003	N/A	N/A	12.75%	9.95%	N/A
2004	N/A	N/A	11.37%	9.62%	N/A
2005	117.46	N/A	11.50%	9.62%	N/A
2006	117.94	N/A	9.24%	9.62%	N/A
2007	98.46	103.8	9.99%	8.54%	(5.4)
2008	160.9	102.9	13.35%	8.54%	58.0
2009	140.7	107.1	11.22%	8.54%	33.6
2010	140.2	109.8	10.91%	8.54%	30.4
2011	133.9	110.2	10.38%	8.54%	23.7
2012	149.4	115.3	11.07%	8.54%	34.1
2013	145.3	121.6	10.67%	8.93%	23.7
2014	153.5	127.9	10.72%	8.93%	25.6
2015	150.6	136	9.89%	8.93%	14.6
2016	158.3	152.9	9.24%	8.93%	5.4
2017	180.4	175.9	9.15%	8.93%	4.5
2018	208.9	193.5	9.64%	8.93%	15.4

N/A - Enbridge Gas was not able to find and provide in this response despite making reasonable effort

Powering Ontario's Growth

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The Canada Infrastructure Bank (CIB) has invested $970 million in the project to date, its largest investment in any clean energy project. The investment marked major step forward in demonstrating the significant opportunities of SMRs, and the important role of nuclear power in meeting future demand for reliable, zero-emissions power.

Ontario's leadership in new nuclear technologies, particularly SMRs, is raising the province's international profile to an unprecedented level.

Last November, the Minister of Energy concluded a successful trade mission to Czech Republic, Poland, and Estonia to discuss SMRs, strengthen existing relationships and support European allies looking to build their energy independence in the face of Russian aggression and to help reduce their reliance on coal power. The mission resulted in signing agreements with major European energy companies ČEZ and Synthos Green Energy.

Other jurisdictions are following Ontario's lead. Earlier this year, Estonia's Fermi Energia chose GE Hitachi's SMR technology – the BWRX-300 – for deployment, citing the Darlington SMR project as a factor in their selection decision. Poland's Synthos Green Energy has also signed agreements with Ontario manufacturers to build components in Ontario for SMRs that will be deployed in Poland, as well as a letter of intent with OPG to provide nuclear expertise to Synthos in developing its SMR program.

3.2 Competitive Procurements for New Build Electricity Generation and Storage

In October 2022 the Minister of Energy directed the IESO to acquire 4,000 MW of new electricity generation and storage resources through competitive procurements to ensure the province has the electricity it needs this decade to support a growing population and economy. This procurement will target 2,500 MW of stand-alone energy storage resources and a maximum of 1,500 MW of natural gas generation.

Energy Storage

As Ontario becomes a leader in the batteries of the future by connecting resources and workers in northern Ontario with the manufacturing might of southern Ontario, the procurement of a targeted 2,500 MW of clean energy storage represents the largest battery procurement in Canada's history.

In the first round of the procurement which concluded in May 2023, the IESO has acquired seven new battery storage projects, representing 739 MW of new storage supply.

These facilities will support the operation of Ontario's clean electricity grid by drawing and storing electricity off-peak when power demand is low and intermittent renewable generation is high and returning the power to the system at times of higher electricity demand. The grid will benefit from using more non-emitting energy at peak. Grid-scale energy storage also offers the potential to provide critical flexibility to help keep the system in balance.

Natural Gas Generation

Natural gas generation currently plays a key role in supporting grid reliability, with the ability to respond to changing system needs in ways other forms of supply cannot.

When electricity demand spikes on hot summer days, Ontario's natural gas generators can be turned on and ramped up quickly to ensure the province does not need to be reliant on emergency actions such as conservation appeals and rotating blackouts to stabilize the grid, according to the IESO.

While during most hours throughout the year Ontario can meet its electricity generation needs with nuclear, hydroelectric, bioenergy, wind and solar power, natural gas generation also acts as the province's insurance policy that can be turned on if the wind is not blowing or sun is not shining, or another generator is offline for repairs (see figure 3.3). There is currently no like-for-like replacement for natural gas and the IESO has concluded it is needed to maintain system reliability until nuclear refurbishments are complete and new non-emitting technologies such as storage mature.

This means natural gas will be needed until reliable replacements (such as hydrogen) have been identified, put into service, and demonstrated their capability.

To meet this near-term need the IESO has secured 586 MW of new natural gas capacity from expansions and efficiency upgrades at existing sites through the first round of procurements.

"The government and the IESO are taking a prudent approach by procuring a diverse portfolio of non-emitting resources, with limited natural gas to ensure system reliability over the short-term."

– Rocco Rossi
President and CEO, Ontario Chamber of Commerce

Enbridge Gas consumers have the option of adding RNG to their natural gas supply for $2 per month through the voluntary OptUp program. All the funds generated from the OptUp program are used by Enbridge to purchase locally produced RNG from StormFisher's facility in London, Ontario.

Natural gas will continue to play a critical role in providing Ontarians with a reliable and cost-effective fuel supply for space heating, industrial growth, and economic prosperity. With developments in energy efficiency, and low-carbon fuels such as RNG and low-carbon hydrogen, the natural gas distribution system will help contribute to the province's transition from higher carbon fuels in a cost-effective way.

1.3 Oil and Refined Petroleum Products

Petroleum products, derived from crude oil, comprise just under 40 per cent of Ontario's end-use energy consumption. Petroleum products are critical fuels to move goods and people, heat homes and have non-energy applications.

Transportation fuels account for about 80 per cent of Ontario petroleum consumption —gasoline (49 per cent), diesel (22 per cent), and jet fuel (8 per cent). Non-energy uses of petroleum include inputs to the petrochemical sector (7 per cent) and asphalt (3 per cent). Other applications – including lubricants and heating oil – account for about 10 per cent of overall petroleum demand.

While the first oil well in North America was drilled in Oil Springs, near Sarnia, Ontario crude oil production now accounts for less than one per cent of Ontario refinery requirements today. Ontario relies almost entirely on imported crude oil, primarily delivered by interprovincial and international pipelines. The main pipeline network (Enbridge Mainline) supplying Ontario with crude oil originates in Western Canada and passes through the U.S. before entering Canada near Sarnia (Enbridge Line 5 and Line 78). U.S. crude oil production can also access the U.S. portion of the Enbridge Mainline and supply Ontario. In 2021, about 86 per cent of Ontario's crude oil requirements came from Alberta, Saskatchewan, and British Columbia; 14 per cent came from the U.S.

Ontario's four refineries supply approximately 78 per cent of Ontario's refined product demand, with Quebec and the U.S. supplying the remainder. Pipelines, rail, marine (during the shipping season) and trucks (for delivery to retail gasoline stations) are all part of the supply chain to move fuel from refineries to end-users. Petroleum product infrastructure (terminals, bulk plants, pipelines, retail stations) is owned by private companies in Ontario.

The Sarnia Natural Gas Liquids (NGL) factionator is one of the main sources of propane and butane for eastern Canada. It processes NGL mix delivered from western Canada by the Enbridge Mainline (Lines 1 and 5). From Sarnia, propane is delivered by rail and truck to locations in Ontario, Quebec, other eastern Canadian provinces, and to export markets in the U.S. Midwest and East Coast.

Planning Ahead For 2030-2050

4.0 Introduction

While the Ontario government is moving forward on many fronts to secure the electricity the province needs for the decade, additional action is needed to plan for and meet expected long-term demand between 2030 and 2050.

IESO forecasts that the need for electricity system capacity in Ontario could, under one potential scenario, more than double, from 42,000 MW today to 88,000 MW in 2050. Over this time, up to 20,000 MW in capacity may be needed just to replace generation that will come to the end of its life or be phased out.

While some forms of generation like natural gas generation or intermittent renewables can be built relatively quickly, large infrastructure which can provide baseload power such as hydroelectric, nuclear facilities, and the transmission to get it to population and economic centres, can take 10 to 15 years to build.

The Ontario government is acting now to develop new generation capacity including assessing site potential for the first large-scale nuclear build since 1993, expanding the province's SMR program, and advancing long-duration storage projects so that these facilities are ready when they are needed.

In keeping with its forward-thinking approach to energy planning, the Ontario government asked the IESO to deliver critical reports to inform next steps. These reports and input from Ontarians have formed the basis for the additional actions the Ontario government is taking to meet the province's needs in the longer term which are described in this chapter.

4.1 Pathways to Decarbonization

In October 2021, the Minister of Energy asked the IESO to develop a *Pathways to Decarbonization* report. Released in December 2022, the report recommends "no-regrets" actions that could be taken today to develop needed electricity resources with long-lead times.

1. Accelerating current efforts to acquire new non-emitting supply, including the implementation of recent conservation and demand management directives.

2. Beginning the planning, siting and environmental assessment work needed for new nuclear, long-duration storage and hydroelectric facilities, as well as transmission infrastructure, to allow for faster implementation.

3. Investing in emerging technologies like low-carbon fuels. Further work is needed to determine if they can replace at scale some of the flexibility that natural gas currently provides the system.

4. Galvanizing collaboration among stakeholders and Indigenous communities.

5. Ensuring that regulatory, approval and permitting processes are ready to manage future investment at scale.

Pathways to Decarbonization

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

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Pathways: Conclusion and Outcomes

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

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

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

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

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

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