EB-2024-0186 and EB-2024-0197

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B, as amended (the "**OEB Act**");

AND IN THE MATTER OF a motion by Federation of Rental-Housing Providers of Ontario ("**FRPO**") and Environmental Defence ("**ED**") pursuant to rule 42 of the *Rules of Practice and Procedure* of the Ontario Energy Board (the "**OEB**") to review and vary OEB decisions in EB-2022-0111, EB-2023-0200, EB-2023-0201, and EB-2023-0261

Book of Authorities*

Review Motions and Stay Requests

**This BOA only includes sources that are not hyperlinked in the submissions*

September 12, 2024

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Ontario Energy Board | Commission de l'énergie de l'Ontario

Report to the Minister of Energy, Northern Development and Mines and to the Associate Minister of Energy

EB-2019-0255

Potential Projects to Expand Access to Natural Gas Distribution

October 30, 2020

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EXECUTIVE SUMMARY

On December 12, 2019, the Minister of Energy, Northern Development and Mines, with the support of the Associate Minister of Energy, asked the Ontario Energy Board (OEB) to solicit information from proponents about proposed natural gas distribution expansion projects, to analyze the project information filed and to report back to the Ministry of Energy, Northern Development and Mines.

As the Ministers' letter notes, the Ontario Government intends to further increase access to natural gas by making additional new projects eligible for approximately $130 million in ratepayer-funded financial support. This financial support is intended to be for projects that can reasonably be expected to commence construction between 2021 and 2023, and that would under existing policies be considered uneconomic.

The OEB was asked to consider several factors in soliciting and analyzing information from project proponents, with a focus on assessing whether proposed projects can be implemented substantially as proposed. The report requested of the OEB is intended as an input to assist the government in making a determination on future expansion projects. The OEB was not asked to rate or rank the proposed projects or provide recommendations regarding which should receive funding support.

This report sets out information on 210 proposed gas expansion projects received from three project proponents: Enbridge Gas Inc., EPCOR Natural Gas Limited Partnership, and Lakeshore Natural Gas Inc. In the aggregate, these proposed projects have the potential to connect approximately 44,000 new customers and would require approximately $2.6 billion in funding support. Absent that funding support, each of the proposed projects would be uneconomic under existing policies.

Roughly 60% of the proposed projects are situated in southwest and southeast Ontario, with the remainder being spread elsewhere across the province. Seven of the proposed projects include service to on-reserve First Nation communities. The overwhelming majority of the proposed projects have an estimated construction start date in the second quarter of 2023, with the estimated construction start date for the remaining projects being in the first half of 2022.

Based on the information received from project proponents, the OEB has not identified any significant impediments to the implementation of the proposed projects substantially as proposed. Of particular importance in this regard is the fact that all proponents demonstrated a commitment to being held to their project costs and volumes in the form of a ten-year rate stability period for each of their proposed projects.

1. INTRODUCTION

1.1 The Section 35 Letter

On December 12, 2019, the Ontario Energy Board (OEB) received a letter (Section 35 Letter) from the Minister of Energy, Northern Development and Mines and the Associate Minister of Energy under section 35 of the *Ontario Energy Board Act, 1998* (OEB Act) indicating that the Government intends to make $130 million available to support new natural gas projects that would otherwise be uneconomic under existing policies, and that can reasonably be expected to commence construction between 2021 and 2023.

The Section 35 Letter requires the OEB to examine and report back to the Ministry of Energy, Northern Development and Mines (Ministry) by August 31, 2020 (a deadline which was later extended to October 31, 2020 due to the COVID-19 pandemic) with information on potential projects that the Government could consider as candidates for financial support to expand access to natural gas distribution to communities that are not currently connected to a natural gas distribution system. To that end, the Section 35 Letter asked the OEB to apply its expertise to develop a process to solicit information on proposed natural gas expansion projects, and to analyze the projects with a focus on assessing whether they can be implemented substantially as proposed. The Section 35 Letter states that this should include a demonstrated commitment by each proponent that it would be willing to be held to the project cost, timelines and volumes forecasts as set out in their project proposal.

The Section 35 Letter identified the following as matters to be considered by the OEB:

- The number of customers (in terms of customer count, volume of gas to be distributed and customer type) that would be connected by each proposed project.

- The total cost of each proposed project, as well as the dollar amount of support needed for each proposed project to meet the OEB’s profitability threshold.

- The proposed construction start date and construction period for each proposed project, as the provincial Government’s focus is on projects that can reasonably be expected to start construction by 2023, allowance being made for the timelines typically applicable to the process of obtaining regulatory approvals.

- The project proponent’s demonstrated experience, technical expertise and financial ability to build and operate a natural gas distribution system.

- Support for the proposed project from Band Council(s) and/or local government, as applicable, demonstrated through a written expression of support and/or a commitment to financial support.

- If a proposed project is in an area where a Certificate of Public Convenience and Necessity (Certificate)[1] exists, the proponent must be the Certificate holder unless the Certificate holder does not propose a project for the area.

- The extent to which the project proponent expects that the proposed project would reduce the household energy cost burden in the project area.

1.2 Background on Funding Support for Natural Gas Expansion Projects

On July 1, 2019, section 36.2 of the OEB Act came into force. That section, which was added to the OEB Act by the *Access to Natural Gas Act, 2018*, establishes a framework for the funding of natural gas expansion projects by natural gas ratepayers.

Ontario Regulation 24/19, Expansion of Natural Gas Distribution Systems (Regulation), currently sets out nine projects that are eligible for financial support subject to receiving any necessary OEB approvals, the mechanism by which funding is collected from ratepayers and distributed to the project proponents, and related matters. The Regulation also requires that rate-regulated natural gas distributors charge each of their customers $1 per month (for each account that the customer has with the natural gas distributor) to provide funding for the eligible expansion projects.

The Section 35 Letter states that the Government intends to use the mechanism articulated in the Regulation – namely, the collection of $1 per month from existing natural gas customers – to provide approximately $130 million in financial support for new natural gas projects that can reasonably be expected to commence construction between 2021 and 2023. Changes to the Regulation will be required to enable the provision of ratepayer-funded financial support for any such projects.

[1] Section 8 of the *Municipal Franchises Act* states that no person shall construct any works to supply natural gas in any municipality without the prior approval of the OEB, and that such approval shall not be given unless public convenience and necessity appear to require that such approval be given. A Certificate is issued by the OEB after the OEB has approved a proponent's application to construct works to supply natural gas within a specified geographical area.

2. THE OEB'S PROCESS

2.1 Development of Guidelines

The Section 35 Letter noted the expectation that the OEB would, in early 2020, issue a call for information, including details of the information to be filed by interested project proponents.

On December 19, 2020, the OEB issued draft *Guidelines for Potential Projects to Expand Access to Natural Gas Distribution* (Draft Guidelines) for stakeholder comment.

Twenty-one stakeholders submitted comments, including natural gas distributors, compressed natural gas (CNG) and liquefied natural gas service providers, ratepayer groups, industry associations, environmental groups and groups representing Indigenous peoples.[2]

On March 5, 2020, the OEB issued its final *Guidelines for Potential Projects to Expand Access to Natural Gas Distribution* (Final Guidelines). At that time, the OEB indicated that interested project proponents that wished to file project information for inclusion in the OEB's report to the Ministry were to do so by June 3, 2020.

On April 14, 2020 the OEB issued a frequently asked questions (FAQ) document to assist proponents with questions regarding the Final Guidelines, and on April 17, 2020 the OEB updated those FAQs.

On April 29, 2020, the OEB issued a letter asking interested proponents to identify any proposed projects that may not be completed by the June 3, 2020 deadline as a result of the COVID-19 emergency.

On May 15, 2020, the OEB received a letter from the Minister of Energy, Northern Development and Mines and the Associate Minister of Energy, extending the deadline for the OEB to report back to the Ministry from August 31, 2020 to October 31, 2020. The OEB accordingly extended the deadline for project proponents to submit information on their proposed projects from June 3, 2020 to August 4, 2020.

[2] Comments were received from Anwaatin Inc., Bingwi Neyaashi Anishinaabek First Nation and Red Rock Indian Band, Building Owners and Managers Association, Canadian Propane Association, Certarus, Consumers Council of Canada, the Town of Marathon, Enbridge Gas Inc., Energy Probe, Environmental Defence, EPCOR Natural Gas Limited Partnership, Federation of Rental-housing Providers of Ontario, Green Energy Coalition, Industrial Gas Users Association, Northeast Midstream, Northwatch, NWCOC Coalition, Ontario Federation of Agriculture, Pollution Probe, School Energy Coalition, and Vulnerable Energy Consumers Coalition.

2.2 Confidentiality

In its consultation on the Draft Guidelines, the OEB asked interested projects proponents to identify any information that they believe should be treated as confidential. The OEB received relatively few comments on this issue, and neither of the existing rate-regulated natural gas distributors provided comments related to confidentiality. In its letter accompanying the Final Guidelines, the OEB confirmed that it intended to post each proponent's project information on the OEB website following the deadline for filing project information.[3]

On July 17, 2020, the OEB received a letter from Enbridge Gas Inc. (Enbridge Gas) requesting that all information related to projects proposed by it and by any other proponent be kept confidential and not be posted on the OEB's website or made available pursuant to declarations and undertakings as contemplated by the OEB. On July 29, 2020, the OEB issued a letter inviting interested proponents to comment on Enbridge Gas's request. On October 28, 2020, the OEB issued its determination on confidentiality. The OEB accepted that the disclosure of information related to the financial viability of potential projects could negatively impact Enbridge Gas's (or any other proponents') competitive position in any future gas expansion initiatives, the scope and specifics of which are unknown at this time, and should therefore remain confidential. Subject to any redactions as may be required to remove personal information as defined in the *Freedom of Information and Protection of Privacy Act* or to remove information which may give rise to legitimate safety concerns, the OEB determined that all project information other than data and economic measures related to the financial viability of projects will be placed on the public record for each project. Redacted versions of the 210 project proposals will be posted on the OEB's website in due course once those versions have been received from the project proponents.

[3] By way of exception, and as discussed below, the OEB also indicated that it would not include in its report any proposed project from a non-Certificate holder unless the existing Certificate holder does not bring forward a project for the same area, and that the OEB would not be posting project information for projects that are not included in the OEB's review.

3. SUMMARY OF PROPOSED PROJECTS AND ASSUMPTIONS

The Section 35 Letter did not ask the OEB to provide a ranking or rating of proposed projects, or to make recommendations regarding which should receive funding support.

This report therefore provides a summary of the proposed projects (section 3) and a discussion of implementation considerations (section 4), including the OEB's assessment of whether the proposed projects can be implemented substantially as proposed.

3.1 Number and Geographic Distribution

The OEB received project information for a total of 213 proposed projects.

The Section 35 Letter stated that, for any proposed project submitted for an area where a Certificate exists, the project proponent must be the Certificate holder unless the Certificate holder does not propose a project for that area. In its Final Guidelines, the OEB indicated that it would not include in its report any proposed project from a non-Certificate holder unless any existing Certificate holder did not bring forward a project for the same area.

Three of the 213 proposed projects submitted are for areas that overlap with projects submitted by Enbridge Gas and for which Enbridge Gas is the Certificate holder. Consequently, the three overlapping proposed projects have not been included in this report.

A fourth proposed project, submitted by EPCOR Natural Gas Limited Partnership (EPCOR) for the Municipality of Brockton (and nearby areas), also overlaps with one of Enbridge Gas's proposed projects. Enbridge Gas currently holds the Certificate for the Municipality of Brockton and the Municipality of West Grey, which covers all parts of these municipalities except for a portion in which EPCOR is authorized through a Certificate to locate its traversing pipeline to serve the community of Southern Bruce. The OEB has included both EPCOR's and Enbridge Gas's proposed projects in this report because both EPCOR and Enbridge Gas hold Certificates for the area.

This report therefore covers 210 projects filed by the following proponents: Enbridge Gas, EPCOR, and Lakeshore Natural Gas Inc. on its own behalf and as representative of the Town of Marathon, Township of Manitouwadge, Township of Schreiber, Township of Terrace Bay and the Municipality of Wawa (Lakeshore). Table 1 below depicts the number of proposed projects by project proponent that are included in this report.

Table 1. Number of proposed projects, by proponent

Project Proponent	Number of Proposed Projects
Enbridge Gas	207
EPCOR	2
Lakeshore	1
TOTAL	**210**

Although the proposed projects filed with the OEB cover most parts of the province, as demonstrated in Table 2 below, roughly 60% of the proposed projects are located in southwest or southeast Ontario.

Table 2. Proposed projects by geographic location

	Central	NE	NW	SE	SW	Total
Forecasted customers (#)	6,408	4,617	4,950	19,369	8,706	44,050
Projects filed (#)	34	31	23	66	56	210
Forecasted customers per region (% of total)	14.5	10.5	11.2	44.0	19.8	
Funding support per region	$409,491,924	$395,848,944	$240,858,654	$1,009,439,717	$516,608,786	$2,572,248,025
Funding support per region (% of total)	16	15	10	39	20	

For ease of geographic reference, the proposed projects have been plotted onto maps. Figure 1 provides a map view of all 210 proposed projects.[4] Detailed region-specific maps are included in Appendix 1.

[4] Location names have been bolded only to provide geographic reference points for project locations.

Figure 1. Map of proposed projects

3.2 Summary Table

Table 3 below provides a summary of the following key information about each of the 210 proposed projects included in this report: the name of the proposed project (in alphabetical order); the project proponent; the total funding support required;[5] the funding support required per forecast customer in year ten; the total number of forecast customers in year ten; the estimated annual fuel cost savings in year ten; the estimated annual GHG impacts in year ten; and whether the proposed project received any letter(s) of support. Of the 210 proposed projects, 7 include serving on-reserve First Nation communities.[6] Further information about the methodology and assumptions used by project proponents in relation to some of these project parameters is set out in section 3.3.

By way of overview, in the aggregate, the 210 proposed projects have the potential to connect approximately 44,000 new customers, with an average of 209 customers per proposed project. The total funding support that would be required for all 210 projects amounts to approximately $2.6 billion. The funding support required for each of the proposed projects ranges from approximately $320,000 to over $125 million.

Table 3. Summary of Proposed Projects

No.	Proponent	Proposed Project	Total Funding Support Required ($)	Funding Support per Forecast Customer (year 10) ($)	Total # of forecast customers (year 10)	Est. Annual Fuel Cost Savings ($) (year 10)	Estimated GHG impacts (tCO2e)	Letter(s) of support
1	Enbridge Gas	Adelaide Metcalfe (North)	10,181,974	128,886	79	47,817	-19	Y
2	Enbridge Gas	Adelaide Metcalfe (South)	14,998,212	111,927	134	81,107	-33	Y
3	Enbridge Gas	Alberton	9,895,573	137,439	72	30,823	-14	Y
4	Enbridge Gas	Alderville, Roseneath and Alderville FN	18,916,120	64,560	293	125,432	-55	N
5	Enbridge Gas	Allenford	5,724,864	48,516	118	44,915	-16	Y
6	Enbridge Gas	Ameliasburgh and Rossmore	38,840,800	49,924	778	333,059	-147	Y
7	Enbridge Gas	Aroland and Nakina	53,029,240	240,495	221	94,609	-42	N
8	Enbridge Gas	Ashfield-Colborne-Wawanosh - Benmiller	5,733,161	92,470	62	34,417	-57	Y
9	Enbridge Gas	Ashfield-Colborne-Wawanosh - Dungannon	27,648,393	151,914	182	110,160	-45	Y

[5] The “total funding support required” is determined for each proposed project based on the amount of funding support that would be required to bring the profitability index for the proposed project to 1.0.
[6] Alderville, Roseneath and Alderville First Nation; Aroland and Nakina; Mohawks of the Bay of Quinte First Nation; Red Rock First Nation (Lake Helen Reserve); Thessalon First Nation; Wabigoon First Nation; and Wauzhushk Onigum First Nation.

No.	Proponent	Proposed Project	Total Funding Support Required ($)	Funding Support per Forecast Customer (year 10) ($)	Total # of forecast customers (year 10)	Est. Annual Fuel Cost Savings ($) (year 10)	Estimated GHG impacts (tCO2e)	Letter(s) of support
10	Enbridge Gas	Ashfield-Colborne-Wawanosh - Dungannon and Port Albert	39,758,502	144,053	276	167,056	-67	Y
11	Enbridge Gas	Astorville	23,574,415	61,875	381	118,717	-105	Y
12	Enbridge Gas	Auburn	6,289,434	58,235	108	51,829	-82	Y
13	Enbridge Gas	Augusta Township	1,481,157	31,514	47	13,508	-41	Y
14	Enbridge Gas	Avonmore, Monkland, Bloomington	32,163,924	91,116	353	151,118	-66	Y
15	Enbridge Gas	Ayton and Neustadt	15,627,755	36,685	426	218,971	-311	Y
16	Enbridge Gas	Bainsville and South Glengarry	7,076,937	32,315	219	131,984	-48	Y
17	Enbridge Gas	Ballinafad and Silver Creek	12,121,282	41,798	290	178,764	-255	Y
18	Enbridge Gas	Belwood	8,798,271	49,152	179	94,425	-168	Y
19	Enbridge Gas	Black River-Matheson	8,722,663	235,748	37	16,973	-7	Y
20	Enbridge Gas	Blandford-Blenheim - Canning	1,950,063	75,002	26	15,737	-6	Y
21	Enbridge Gas	Blandford-Blenheim - Perry's Corners	1,825,997	130,428	14	8,474	-3	Y
22	Enbridge Gas	Blandford-Blenheim - Ratho	4,386,975	204,999	21	12,711	-5	Y
23	Enbridge Gas	Blandford-Blenheim - Richwood	2,968,422	109,942	27	16,342	-7	Y
24	Enbridge Gas	Bobcaygeon	68,029,650	17,104	3,978	3,060,298	486	Y
25	Enbridge Gas	Boblo Island	1,915,672	20,823	92	55,685	-22	Y
26	Enbridge Gas	Bonfield	11,264,835	52,152	216	99,087	-41	Y
27	Enbridge Gas	Bracebridge	4,919,765	52,338	94	40,241	-18	N
28	Enbridge Gas	Bradford West Gwillimbury (Project A)	3,941,187	63,568	62	37,365	-14	Y
29	Enbridge Gas	Bradford West Gwillimbury (Project B)	9,759,624	250,247	39	23,504	-9	Y
30	Enbridge Gas	Bradford West Gwillimbury (Project C)	4,814,733	104,668	46	27,723	-10	Y
31	Enbridge Gas	Brant County – Harley and Glen Morris	11,236,428	50,207	224	135,582	-55	Y
32	EPCOR	Brockton	20,340,000	40,599	501	236,255	-252	Y
33	Enbridge Gas	Burk's Falls	1,237,071	30,172	41	18,808	-8	Y
34	Enbridge Gas	Burritts Rapids	978,302	32,610	30	18,080	-7	Y
35	Enbridge Gas	Caledon (Project A)	12,199,421	58,934	207	124,752	-45	Y
36	Enbridge Gas	Caledon (Project B)	5,048,975	50,490	100	60,267	-22	Y
37	Enbridge Gas	Caledon (Project C)	8,620,777	61,140	141	84,976	-31	Y
38	Enbridge Gas	Camden East, Yarker, Tamworth and Erinsville	49,492,017	48,427	1,022	437,514	-193	N
39	Enbridge Gas	Carlsbad Springs	10,725,127	24,156	444	267,584	-97	Y
40	Enbridge Gas	Casselman	1,127,309	66,312	17	10,245	-4	Y
41	Enbridge Gas	Cavan Monaghan (Project A)	3,720,341	49,605	75	45,200	-16	Y
42	Enbridge Gas	Cavan Monaghan (Project B)	2,098,225	95,374	22	13,259	-5	Y
43	Enbridge Gas	Cavan Monaghan (Project C)	3,632,641	129,737	28	16,875	-6	Y

No.	Proponent	Proposed Project	Total Funding Support Required ($)	Funding Support per Forecast Customer (year 10) ($)	Total # of forecast customers (year 10)	Est. Annual Fuel Cost Savings ($) (year 10)	Estimated GHG impacts (tCO2e)	Letter(s) of support
44	Enbridge Gas	Cedar Springs	2,517,260	24,439	103	80,051	-81	Y
45	Enbridge Gas	Cedar Valley	2,132,768	39,496	54	32,544	-12	Y
46	Enbridge Gas	Charlton and Dack	8,626,988	83,757	103	44,094	-19	Y
47	Enbridge Gas	Chute-à-Blondeau	4,446,983	13,984	318	191,648	-70	Y
48	Enbridge Gas	Conmee	19,732,817	156,610	126	57,801	-24	Y
49	Enbridge Gas	Cornwall Regional Airport	1,221,395	64,284	19	11,451	-4	Y
50	Enbridge Gas	Cotnam Island	5,961,794	64,105	93	77,911	-18	Y
51	Enbridge Gas	Cumnock	8,332,123	94,683	88	53,264	-22	Y
52	Enbridge Gas	Curran	2,082,170	19,643	106	63,883	-23	Y
53	Enbridge Gas	Dorion	4,310,381	113,431	38	16,268	-7	Y
54	Enbridge Gas	Douglas (Admaston/Bromley)	12,756,909	83,378	153	92,208	-34	N
55	Enbridge Gas	Dunrobin Shores	22,952,530	50,115	458	342,112	-98	Y
56	Enbridge Gas	Dutton Dunwich	6,177,075	150,660	41	24,816	-10	Y
57	Enbridge Gas	Ear Falls	1,797,382	199,709	9	4,129	-2	Y
58	Enbridge Gas	East Gwillimbury (North and East)	8,373,365	19,842	422	254,325	-92	Y
59	Enbridge Gas	Edwardsburgh Cardinal and Spencerville	19,118,445	36,278	527	124,550	-370	Y
60	Enbridge Gas	Eganville	26,169,413	38,827	674	406,197	-148	Y
61	Enbridge Gas	Elmwood, Chepstow and Cargill (Brockton)	26,125,754	64,828	403	254,532	-343	Y
62	Enbridge Gas	Emsdale (Township of Perry)	8,949,644	48,376	185	79,198	-35	N
63	Enbridge Gas	Featherstone	4,794,215	19,568	245	89,964	18	Y
64	Enbridge Gas	Field	10,085,042	70,525	143	61,218	-27	N
65	Enbridge Gas	Forest Harbour (Tay Twp)	16,551,839	84,448	196	118,122	-43	Y
66	Enbridge Gas	Georgian Bluffs	2,974,796	32,335	92	55,685	-22	Y
67	Enbridge Gas	Gillies and O'Connor	11,956,264	107,714	111	47,519	-21	N
68	Enbridge Gas	Glen Tay (Tay Valley)	2,309,186	28,161	82	49,419	-18	N
69	Enbridge Gas	Glendale	2,352,112	30,547	77	36,470	101	Y
70	Enbridge Gas	Gores Landing	13,049,627	43,499	300	128,429	-57	N
71	Enbridge Gas	Grimsby-Lincoln (Economic Development)[7]	4,295,182	477,242	9	0	0	Y
72	Enbridge Gas	Haldimand - Dunnville (Economic Development)	45,509,449	6,501,350	7	0	0	Y
73	Enbridge Gas	Haldimand - Nanticoke (Economic Development)	109,011,394	12,112,377	9	0	0	Y
74	Enbridge Gas	Haldimand Shores	2,827,923	25,944	109	39,466	-80	Y

[7] Enbridge Gas submitted four proposed projects described as "Economic Development" projects. These projects are intended primarily to serve the agricultural or industrial sectors and do not include a customer attachment forecast for residential customers.

No.	Proponent	Proposed Project	Total Funding Support Required ($)	Funding Support per Forecast Customer (year 10) ($)	Total # of forecast customers (year 10)	Est. Annual Fuel Cost Savings ($) (year 10)	Estimated GHG impacts (tCO2e)	Letter(s) of support
75	Enbridge Gas	Hamilton - Alberton	1,531,806	90,106	17	10,290	-4	Y
76	Enbridge Gas	Hamilton - Rockton	5,716,530	47,244	121	73,239	-30	Y
77	Enbridge Gas	Hamilton - Sheffield	3,688,318	56,743	65	48,931	-80	Y
78	Enbridge Gas	Hamilton - Westover	3,732,828	46,660	80	48,422	-20	Y
79	Enbridge Gas	Hamilton Airport Regional Expansion (Economic Development)	10,331,404	860,950	12	0	0	Y
80	Enbridge Gas	Harley	11,213,541	133,495	84	38,534	-16	Y
81	Enbridge Gas	Hidden Valley (Huntsville)	1,899,859	18,445	103	44,094	-19	Y
82	Enbridge Gas	Hornepayne	49,847,482	144,068	346	158,723	-65	Y
83	EPCOR	Huron-Kinloss & Municipality of Kincardine	7,509,000	65,293	115	77,611	19	Y
84	Enbridge Gas	Jogues	7,518,889	129,636	58	24,830	-11	N
85	Enbridge Gas	Kaministiquia	19,046,539	126,136	151	64,642	-28	N
86	Enbridge Gas	Kawartha Lakes - Kirkfield, Coboconk and Norland	127,221,409	134,484	946	570,122	-207	Y
87	Enbridge Gas	Kawartha Lakes - Scugog	28,138,012	33,065	851	512,868	-186	Y
88	Enbridge Gas	Kawartha Lakes - Woodville	8,629,036	33,576	257	154,885	-56	Y
89	Enbridge Gas	Kenora District	956,804	31,893	30	13,762	-6	Y
90	Enbridge Gas	King Township (Kettleby)	3,802,863	45,818	83	50,021	-18	Y
91	Enbridge Gas	King Township (North Nobleton)	8,171,526	50,395	162	97,632	-35	Y
92	Enbridge Gas	Kinkora	3,072,782	105,958	29	17,553	-7	Y
93	Enbridge Gas	Lanark and Balderson	12,673,429	37,944	334	201,290	-73	Y
94	Enbridge Gas	Latchford	6,970,298	57,134	122	55,966	-23	Y
95	Enbridge Gas	Laurentian Valley	7,941,215	39,509	201	121,136	-44	Y
96	Enbridge Gas	Lavigne	5,962,418	97,745	61	26,114	-11	N
97	Enbridge Gas	Lefaivre	20,112,562	81,758	246	148,256	-54	Y
98	Enbridge Gas	Limehouse	4,047,429	64,245	63	38,132	-15	Y
99	Enbridge Gas	Lisle and Tioga	9,657,355	26,314	367	221,178	-80	Y
100	Enbridge Gas	Little Longlac	318,754	53,126	6	2,569	-1	N
101	Enbridge Gas	Long Point (Norfolk County)	19,267,317	33,981	567	343,192	-139	N
102	Enbridge Gas	Mallorytown	21,231,039	56,616	375	226,000	-82	Y
103	Enbridge Gas	Mansfield	9,047,094	37,231	243	156,697	76	Y
104	Enbridge Gas	Marks Township	11,741,677	131,929	89	38,101	-17	N
105	Enbridge Gas	Markstay-Warren	2,163,390	44,151	49	20,977	-9	N
106	Enbridge Gas	Marsville	6,953,079	81,801	85	62,112	-33	Y
107	Enbridge Gas	Massey, Webbwood, McKerrow	39,464,372	59,434	664	284,256	-125	N
108	Enbridge Gas	Mattawa	1,034,567	47,026	22	10,092	-4	Y
109	Enbridge Gas	Maxville	12,526,564	38,543	325	195,866	-71	Y
110	Enbridge Gas	McDougall (Project A)	32,771,572	108,876	301	128,857	-57	N

No.	Proponent	Proposed Project	Total Funding Support Required ($)	Funding Support per Forecast Customer (year 10) ($)	Total # of forecast customers (year 10)	Est. Annual Fuel Cost Savings ($) (year 10)	Estimated GHG impacts (tCO2e)	Letter(s) of support
111	Enbridge Gas	McDougall (Project B)	21,387,300	125,808	171	72,776	-32	N
112	Enbridge Gas	Meaford - Leith	4,944,867	37,461	132	79,897	-32	Y
113	Enbridge Gas	Meaford - Sunnyside Beach	5,346,148	39,897	134	52,407	-10	Y
114	Enbridge Gas	Merrickville-Wolford	2,465,037	36,792	67	40,379	-15	Y
115	Enbridge Gas	Mississippi Mills	56,026,869	115,282	486	292,895	-106	Y
116	Enbridge Gas	Mohawks of the Bay of Quinte FN	8,080,907	64,134	126	45,332	-24	Y
117	Enbridge Gas	Molesworth	5,243,655	97,105	54	32,685	-13	Y
118	Enbridge Gas	Monkton	13,496,041	64,885	208	125,898	-51	Y
119	Enbridge Gas	Mono (Hockley Village)	6,815,189	34,771	196	118,122	-43	Y
120	Enbridge Gas	Moose Creek	28,925,721	73,045	396	169,526	-75	Y
121	Enbridge Gas	Morris-Turnberry (Walton)	6,985,293	145,527	48	29,053	-12	Y
122	Enbridge Gas	Neebing	13,505,699	155,238	87	39,910	-16	Y
123	Enbridge Gas	Neustadt	5,128,997	23,420	219	160,247	-265	Y
124	Enbridge Gas	North Bay / East Ferris	9,211,148	68,231	135	57,793	-25	Y
125	Enbridge Gas	North Clarington	9,318,027	23,412	398	215,930	-455	Y
126	Enbridge Gas	North Dumfries (Clyde)	4,455,779	34,275	130	78,686	-32	Y
127	Enbridge Gas	North Dumfries (Wrigley and Plumtree)	2,008,504	47,822	42	25,422	-10	Y
128	Enbridge Gas	North Dundas (Project A)	3,437,285	190,960	18	7,706	-3	Y
129	Enbridge Gas	North Dundas (Project B)	9,701,073	36,063	269	115,158	-51	Y
130	Enbridge Gas	North Dundas (Project C)	8,129,130	44,421	183	78,342	-34	Y
131	Enbridge Gas	North Grenville	1,814,425	26,296	69	41,584	-15	Y
132	Enbridge Gas	North Middlesex	10,189,582	203,792	50	30,264	-12	Y
133	Lakeshore	North Shore Gas Distribution Project	38,000,000	12,022	3,161	3,833,248	2,194	Y
134	Enbridge Gas	Norwich Township	6,627,622	114,269	58	35,106	-14	Y
135	Enbridge Gas	O'Connor	7,598,027	110,116	69	29,539	-13	N
136	Enbridge Gas	Oliver Paipoonge	6,250,484	83,340	75	32,107	-14	Y
137	Enbridge Gas	Oro-Medonte	7,357,911	75,855	97	58,459	-21	Y
138	Enbridge Gas	Ottawa - Kinburn-Fitzroy Harbour	23,943,252	53,805	445	268,186	-97	Y
139	Enbridge Gas	Ottawa - Stittsville	11,299,050	82,475	137	82,565	-30	Y
140	Enbridge Gas	Oxford Mills (North Grenville)	8,209,084	57,008	144	86,784	-32	Y
141	Enbridge Gas	Papineau-Cameron	8,244,328	80,042	103	47,250	-19	Y
142	Enbridge Gas	Paradise Point	3,884,439	63,679	61	36,764	-13	Y
143	Enbridge Gas	Perth East (Brunner)	814,850	18,519	44	26,632	-11	Y
144	Enbridge Gas	Perth East (Newton and Millbank)	6,561,393	28,778	228	138,003	56	Y
145	Enbridge Gas	Prince Edward County (Cherry Valley)	5,206,389	34,253	152	65,071	-29	Y
146	Enbridge Gas	Prince Edward County (Consecon and Carrying Place)	9,591,699	30,644	313	133,994	-59	Y

No.	Proponent	Proposed Project	Total Funding Support Required ($)	Funding Support per Forecast Customer (year 10) ($)	Total # of forecast customers (year 10)	Est. Annual Fuel Cost Savings ($) (year 10)	Estimated GHG impacts (tCO2e)	Letter(s) of support
147	Enbridge Gas	Puslinch	2,422,693	121,135	20	12,106	-5	Y
148	Enbridge Gas	Puslinch Lake North	1,730,889	96,161	18	10,895	-4	Y
149	Enbridge Gas	Ramara	42,119,007	24,631	1,710	558,844	335	Y
150	Enbridge Gas	Red Lake (Madsen)	5,383,250	96,129	56	25,689	-11	N
151	Enbridge Gas	Red Lake (McKenzie Island)	1,774,230	44,356	40	18,350	-8	N
152	Enbridge Gas	Red Rock	3,340,784	77,693	43	18,408	-8	Y
153	Enbridge Gas	Red Rock First Nation (Lake Helen Reserve)	3,295,103	42,794	77	30,062	-15	Y
154	Enbridge Gas	Remi Lake (Moonbeam)	14,796,684	150,987	98	41,953	-18	N
155	Enbridge Gas	River Valley (West Nipissing)	2,444,632	49,890	49	20,977	-9	N
156	Enbridge Gas	Roblin & Marlbank	15,018,839	100,126	150	64,214	-28	Y
157	Enbridge Gas	Rosseau (Township of Seguin)	41,609,700	170,532	244	111,932	-46	N
158	Enbridge Gas	Sandford	4,392,566	31,375	140	84,373	-31	Y
159	Enbridge Gas	Sarsfield	7,369,447	31,226	236	142,229	-52	Y
160	Enbridge Gas	Saugeen Shores	12,777,920	159,724	80	48,422	-20	Y
161	Enbridge Gas	Saugeen Shores - Southampton	2,541,601	77,018	33	19,974	-8	Y
162	Enbridge Gas	Scotland	3,215,050	110,864	29	17,553	-7	Y
163	Enbridge Gas	Seguin	25,103,604	164,076	153	70,187	-29	N
164	Enbridge Gas	Selwyn	1,674,964	21,753	77	46,405	-17	Y
165	Enbridge Gas	Severn (Project A)	1,666,738	79,368	21	14,654	-16	N
166	Enbridge Gas	Severn (Project B)	5,539,285	45,404	122	73,525	-27	N
167	Enbridge Gas	Severn (Project C)	19,204,171	26,562	723	313,689	-408	Y
168	Enbridge Gas	Shuniah	6,463,144	37,796	171	78,444	-32	Y
169	Enbridge Gas	South Bruce (Deemerton)	2,004,700	91,123	22	13,316	-5	Y
170	Enbridge Gas	South Dundas	6,101,876	48,815	125	53,512	-24	Y
171	Enbridge Gas	South Stormont (Project A)	15,927,671	109,846	145	62,074	-27	N
172	Enbridge Gas	South Stormont (Project B)	7,785,571	72,762	107	45,806	-20	N
173	Enbridge Gas	South Stormont (Project C)	883,628	32,727	27	11,559	-5	N
174	Enbridge Gas	Southwest Middlesex	6,619,002	169,718	39	23,606	-10	Y
175	Enbridge Gas	Springvale (Haldimand County)	4,317,279	51,396	84	50,843	-21	Y
176	Enbridge Gas	St. Charles	6,385,185	39,415	162	74,316	-31	Y
177	Enbridge Gas	St. Isidore	27,535,894	71,337	386	232,629	-85	Y
178	Enbridge Gas	Project 178[8]	376,205	34,200	11	6,629	-2	Y
179	Enbridge Gas	Sudbury (Project A)	2,568,396	80,262	32	13,699	-6	N
180	Enbridge Gas	Sudbury (Project B)	2,619,026	40,922	64	27,398	-12	N
181	Enbridge Gas	Swiss Meadows	3,583,727	48,429	74	37,485	70	Y

[8] The name of this project has been altered in order not to disclose the name of a potential customer.

No.	Proponent	Proposed Project	Total Funding Support Required ($)	Funding Support per Forecast Customer (year 10) ($)	Total # of forecast customers (year 10)	Est. Annual Fuel Cost Savings ($) (year 10)	Estimated GHG impacts (tCO2e)	Letter(s) of support
182	Enbridge Gas	Temagami	3,150,992	286,454	11	4,709	-2	N
183	Enbridge Gas	Thessalon First Nation	5,079,693	80,630	63	24,596	-12	N
184	Enbridge Gas	Thomasburg (Tweed)	9,081,835	93,627	97	41,525	-18	Y
185	Enbridge Gas	Thunder Lake and Meadows (Dryden)	9,766,160	65,988	148	63,358	-28	Y
186	Enbridge Gas	Timiskaming District (King Kirkland, Larder Lake, Virginiatown, Kearns) (CNG)	23,627,357	43,917	538	189,600	-101	Y
187	Enbridge Gas	Timmins (Project A)	2,525,133	54,894	46	19,692	-9	N
188	Enbridge Gas	Timmins (Project B)	936,593	234,148	4	1,712	-1	N
189	Enbridge Gas	Turkey Point	15,912,080	33,289	478	163,410	153	Y
190	Enbridge Gas	Turkey Point and Normandale	19,543,541	36,394	537	325,034	-131	Y
191	Enbridge Gas	Tweed	3,800,656	61,301	62	26,542	-12	Y
192	Enbridge Gas	Tyendinaga	21,630,613	52,887	409	175,091	-77	Y
193	Enbridge Gas	Val-Côté	4,996,314	146,950	34	15,597	-6	Y
194	Enbridge Gas	Wabigoon	3,649,442	51,401	71	32,570	-13	N
195	Enbridge Gas	Wabigoon First Nation	6,065,771	83,093	73	28,500	-14	N
196	Enbridge Gas	Warsaw	14,583,426	86,292	169	101,850	-37	Y
197	Enbridge Gas	Warwick	8,157,371	70,934	115	64,612	-65	Y
198	Enbridge Gas	Wauzhushk Onigum First Nation	2,981,129	47,320	63	24,596	-12	N
199	Enbridge Gas	Whitewater Region (Project A)	619,252	103,209	6	3,616	-1	Y
200	Enbridge Gas	Whitewater Region (Project B)	1,568,922	78,446	20	12,053	-4	Y
201	Enbridge Gas	Whitewater Region (Project C)	10,931,902	57,536	190	114,506	-42	Y
202	Enbridge Gas	Whitewater Region (Project D)	5,032,109	58,513	86	51,829	-19	Y
203	Enbridge Gas	Whitewater Region (Project E)	4,565,221	32,609	140	84,373	-31	Y
204	Enbridge Gas	Wilkinson	3,526,328	39,622	89	53,637	-19	Y
205	Enbridge Gas	Williamsford and McCullough Lake	5,945,819	33,783	176	75,332	-78	Y
206	Enbridge Gas	Wollaston	77,873,134	299,512	260	111,305	-49	Y
207	Enbridge Gas	Woodham and Kirkton	9,777,609	74,073	132	79,897	-32	Y
208	Enbridge Gas	Wroxeter, Gorrie and Fordwich	38,450,594	68,662	560	286,082	-143	Y
209	Enbridge Gas	Zephyr, Udora, Leaskdale	17,387,484	38,298	454	315,168	-60	Y
210	Enbridge Gas	Zorra Township (Kintore)	20,052,662	153,074	131	79,291	-32	Y
		TOTAL	**2,572,248,025**	**35,529,989**	**44,087**	**25,866,032**	**-6,030**	
		AVERAGE	**12,248,800**	**169,190**	**210**	**123,172**	**-29**	

3.3 Methodology and Assumptions: Profitability Index, Annual Savings and GHG Impact

Profitability Index

A profitability index (PI) was used to assess the financial feasibility of each proposed natural gas expansion project. The average PI (without funding support) of the 210 proposed projects is 0.31.

The PI of a proposed project is calculated using a discounted cash flow analysis.[9] The methodology that rate-regulated utilities must follow in calculating a PI for the purposes of obtaining OEB approval for a project was established in the OEB's Report on Distribution System Expansion, which was part of proceeding E.B.O. 188. A PI of 1.0 indicates that the revenues (including funding) of a project are sufficient to cover the costs of the project.

EPCOR and Enbridge Gas calculated their PI based on the methodology established in E.B.O 188. Lakeshore took a different approach, as it is a new utility that currently does not have OEB-approved rates. To ensure that its project would be financially viable, Lakeshore set the PI at 1.0 and calculated the rates necessary to make the project financially viable.

Annual Savings

Section 3.4 of the Final Guidelines indicates that proponents were to provide the estimated annual costs of existing fuels relative to natural gas, as well as the major assumptions (e.g. conversion factors) used in the calculations of annual household savings.

The "estimated annual savings" in Table 3 represents the amount of estimated annual savings in fuel costs for the forecast customer attachments at year ten. Annual fuel savings were determined by subtracting the annual cost of using natural gas from the annual cost of using the current fuel (e.g., fuel oil, propane, electricity). The annual cost of any given fuel was determined by multiplying the annual consumption (e.g., litres or m^3 per year) by the applicable unit rate (e.g., \$/litre or \$/m^3). The estimated annual savings were derived by multiplying the annual savings per fuel type by the forecast customer attachments at year ten for each fuel type. The estimated annual savings did not include

[9] A discounted cash flow analysis takes into account the net present value of the revenues and costs of a project over a specified time period.

the estimated costs of converting heating and water heating equipment to natural gas as these costs are one-time costs rather than annual costs.

The assumptions used by EPCOR and Enbridge were consistent with one another. Lakeshore used different assumptions for the cost of electricity (forced air and baseboard) and propane. Differences in the assumptions used for the cost of propane are attributable to regional pricing. Differences in the cost of electricity are primarily explained by whether a project proponent assumed that the existing Ontario Electricity Rebate would remain in effect in year ten. These assumptions in relation to the cost of propane and electricity result in higher estimated household energy savings for Lakeshore when compared to the assumptions used by EPCOR and Enbridge.

GHG Impact

Section 3.4 of the Final Guidelines states that the assessment of household energy cost impacts should include GHG emission estimates (whether positive or negative) related to converting existing heating and water heating systems to natural gas, as well as the major assumptions (e.g. emission factors) used in the calculations of GHG emissions.

GHG emissions (for existing systems and natural gas systems) were calculated by multiplying the quantity of fuel (or a fuel conversion factor) and the emission factors for that fuel. The total estimated GHG impacts (tCO2e) associated with converting from an existing fuel to natural gas was then derived by comparing GHG emissions associated with existing systems and GHG emissions associated with natural gas systems.[10]

All three proponents used the same or similar emissions factors for natural gas, heating oil, and propane. However, there were differences in the emissions factor used for electricity resulting from differences in the data sources for electricity GHG emission factors. The use of differing emissions factors for electric heating would lead to differences in the calculation of total estimated GHG impacts, indicating that a direct “apples to apples” comparison between the GHG impacts identified by different project proponents may not be possible. However, this difference does not appear to be material and has no impact on whether the proposed projects can be implemented substantially as proposed.

[10] Estimated Annual GHG Change (tCO2e) = Natural Gas Emissions – Propane Emissions – Electricity (Forced Air) Emissions – Electricity (Baseboard) Emissions – Heating Oil Emissions – “Other” Emissions

3.4 Market Penetration Rates

The market penetration rate indicates the percentage of the customer population that is expected to convert to natural gas in any given area. The 210 proposed projects assumed forecast market penetration rates between 43% and 87%, with an average market penetration rate of approximately 65%.[11] These market penetration rates are similar to those of community expansion projects funded by the Natural Gas Grant Program or under section 36.2 of the OEB Act and approved by the OEB,[12] which have market penetration rates between 34% and 83% and an average of approximately 66%.

3.5 Letters of Support

Amongst other things, the Section 35 Letter identifies support for the proposed project from Band Council(s) and/or local government as a matter to be considered by the OEB in this initiative. As such, the Final Guidelines require project proponents to provide letter(s) from the Band Council(s) and/or local government, as applicable, stating support for the proposed project, including details of any commitment to financial support.

Of the 210 proposed projects, letters of support from municipalities were provided for 166 of them. A number of these letters of support from municipalities also indicated an intention to provide the proponent with municipal tax relief for the proposed natural gas expansion project for a period of ten years or more.

Of the seven proposed projects that include serving on-reserve First Nation communities, only two letters of support were received from the First Nation: a Band Council Resolution from the Red Rock First Nation, and a letter of support from Mohawks of the Bay of Quinte First Nation.

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[11] These penetration rates represent all customer classes (residential, commercial, and industrial).

[12] Kettle and Stony Point First Nation and Lambton Shores; Milverton, Rostock and Wartburg; Delaware Nation of Moraviantown; Prince Township; Fenelon Falls; Scugog Island; South Bruce; Chippewas of the Thames First Nation; Saugeen First Nation and North Bay.

4. IMPLEMENTATION CONSIDERATIONS

The Section 35 Letter asked the OEB to analyze proposed projects to assess whether the projects could be implemented substantially as proposed. To assist its analysis in that regard, the OEB required information from proponents regarding the number of proposed projects, the proposed construction start date for each project, information regarding the technical and financial capabilities of the proponent, and confirmation of a 10-year rate stability period. Based on the information received, the OEB has not identified any significant impediments to the ability of the project proponents to implement their proposed projects substantially as proposed.

4.1 Construction Start Date

Section 3.5 of the Final Guidelines requires project proponents to provide proposed schedules for construction, including the intended in-service date for each proposed project. Enbridge Gas filed 183 proposed projects with an estimated construction start date in the second quarter of 2023. While there may be some concern about the feasibility of a single proponent beginning construction of a large number of projects simultaneously – as that would not only require the proponent to obtain all approvals required (both OEB approvals and any other approvals that may be necessary) within the same time frame, but also prepare and manage multiple construction sites across the province simultaneously – only a small number of these proposed projects is likely to secure funding support. The amount of funding support required for the 210 proposed projects (approximately $2.6 billion) far exceeds the $130 million in funding support that the Government has indicated it intends to make available at this time. As such, the number of proposed projects that may receive funding support is expected to be far fewer than the 183 proposed by Enbridge Gas as commencing in the second quarter of 2023.

The remaining 27 proposed projects indicated an estimated construction start date in the first or second quarter of 2022. Although this is a tighter timeframe in which to apply for and obtain all of the approvals required, there are also fewer projects. It is also noted that the funding support required by these 27 proposed projects would, in aggregate, also exceed the amount of funding support that is intended to be made available at this time.

4.2 Technical and Financial Capability of Proponents

The Final Guidelines include a requirement for project proponents other than rate-regulated natural gas distributors to provide a description of their technical expertise and financial capability to develop, construct, operate and maintain a natural gas distribution system.

Only one proposed project was submitted by a proponent (Lakeshore) that is not currently rate-regulated by the OEB. In regards to providing evidence of its technical expertise, Lakeshore provided information regarding project milestones that have already been achieved, including the creation of an expert Technical Advisory Committee[13] to advise the proponent in relation to the proposed project and the development of an experienced team of external technical consultants and advisors. In addition, Lakeshore has partnered with an experienced natural gas supplier. In regards to its financial capability, as Lakeshore is not yet operational it describes its financial capability by reference to the financial capabilities of the five municipalities involved in the proposed project, including providing consolidated financial statements for each of those municipalities and a financing plan, as well as noting the funding received through a Northern Ontario Heritage Fund grant. Based on the information provided by Lakeshore, there is no indication that Lakeshore would not have the financial and technical expertise needed to undertake its proposed project.[14]

4.3 Rate Stability Period

The Final Guidelines include a requirement for project proponents to confirm that each of their proposed projects includes a ten-year rate stability period. This would provide the demonstrated commitment to be held to the project cost and volumes that was called for in the Section 35 Letter, and the basis on which the OEB would analyze proposed projects with a focus on assessing whether they can be implemented substantially as proposed.

All 210 proposed projects received from proponents confirmed a ten-year rate stability period. The Final Guidelines also require proponents to provide a confirmation that there would be no material cross-subsidization between rate classes.[15] This confirmation was also provided for all 210 proposed projects. The OEB also notes that, in keeping with its approach to avoiding cross-subsidization between existing and new customers, the PI for a proposed project was to be equal to one (1.0), and be calculated on an individual project basis (rather than as part of a portfolio).

[13] The Technical Advisory Committee includes several former gas utility executives, a capital projects expert, a financial management expert, an expert in project construction and management and an expert in stakeholder and Indigenous engagement.
[14] Lakeshore currently does not have Certificates for the municipalities its project proposes to serve, or any other municipalities. The OEB will further assess Lakeshore's financial and technical capabilities when it applies for the necessary Certificates under the *Municipal Franchises Act*.
[15] Final Guidelines, Section 6.1.

4.4 Conclusion

Based on the information received, the OEB has not identified any significant impediments to the ability of the proponents to implement their proposed projects substantially as proposed. Of particular importance in this regard is the fact that all proponents demonstrated a commitment to being held to their project costs and volumes in the form of a ten-year rate stability period for each of their proposed projects. This will help ensure that the risks related to any variances from the forecast costs and revenues of each project will lie with the proponent. Two of the proponents are currently rate-regulated natural gas utilities in Ontario and have significant financial means and experience in building and operating natural gas distribution networks. Although Lakeshore is not yet an operating utility, there is no indication that Lakeshore would not have the financial and technical expertise needed to undertake its proposed project.

Enbridge Gas filed over 200 potential projects. While this could in theory raise resourcing concerns, as a practical matter the OEB does not see this as a significant issue given that the level of funding support that is currently contemplated by the Government would only cover a small number of these proposed projects.

5. APPENDIX 1

The five maps below group the 210 proposed projects into five major regions (central, southeast, southwest, northeast, and northwest).

Proposed projects have been divided into four categories based on the number of forecasted customers to be connected in year ten (as shown in the index for each of the five maps). The yellow indicators represent the proposed projects with the least number of forecasted customer attachments in year ten and the black indicators represent the projects with the highest number of forecasted customer attachments in year ten.

For legibility purposes, location markers are labelled by the project number as it appears in Table 3. The corresponding project name, proponent, and number of forecasted customers can be found in the table following each regional map below.

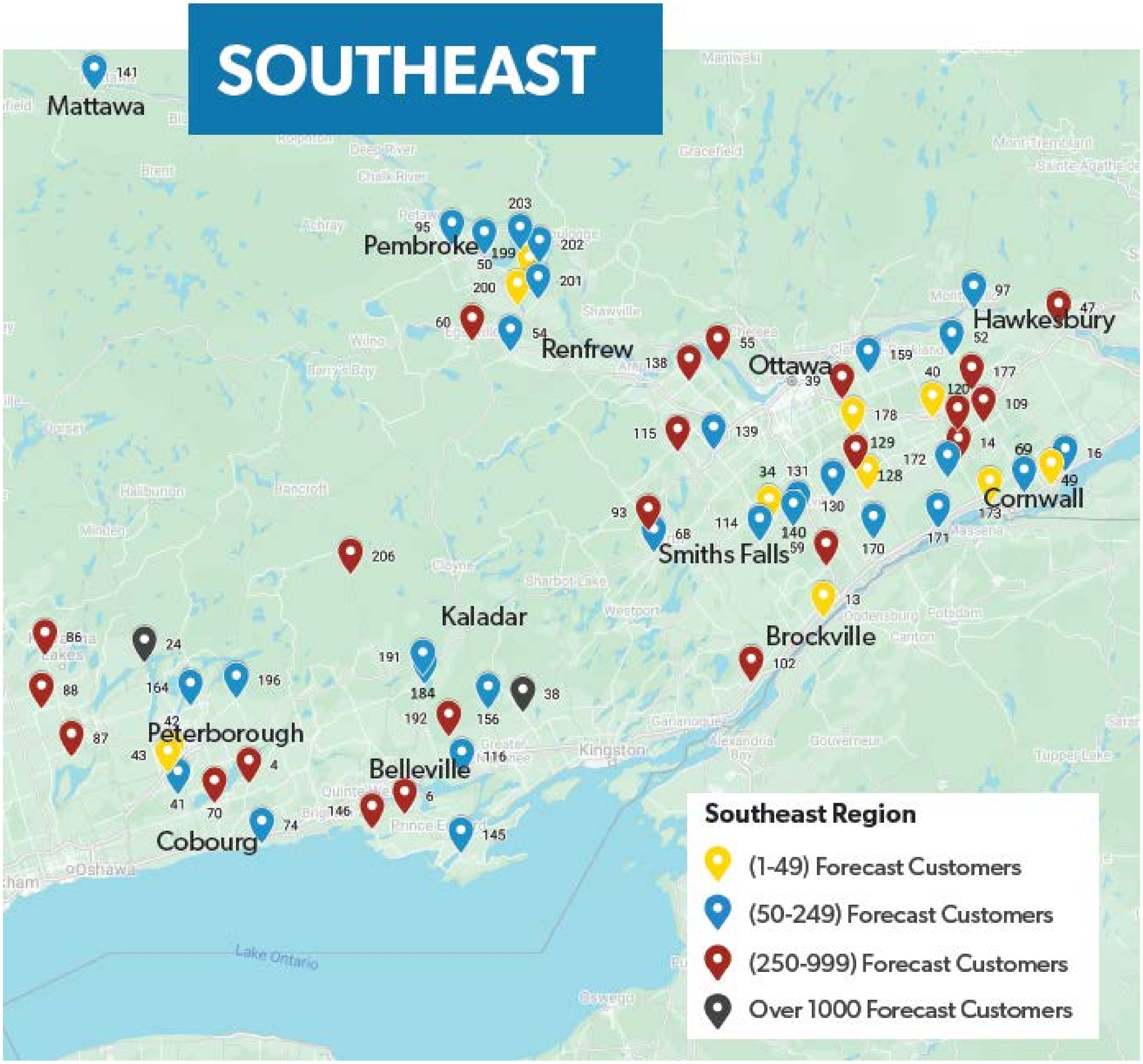
Location names have been marked in bold in the five maps in order to provide geographic reference points for the project locations. Some proposed projects cover several different communities. In these cases, markers have been placed as centrally as possible to provide the general location of the area covered by each project.

Central


CENTRAL
81
Huntsville
27
Bracebridge
166
142
65
167
Midland
165
137
149
Ramara
Barrie
204
99
30
209
29
28
58
36
90
158
Uxbridge
125
Orangeville
35
91
Clarington
106
37
98
Toronto
Mississauga
77
78
44
73
76
Hamilton
75
79
71
St. Catharines
72
Central Region
(1-49) Forecast Customers
(50-249) Forecast Customers
(250-999) Forecast Customers
Over 1000 Forecast Customers

No.	Proposed Project	Proponent	Forecast customers (year 10)
27	Bracebridge	Enbridge Gas Inc.	94
28	Bradford West Gwillimbury (Project A)	Enbridge Gas Inc.	62
29	Bradford West Gwillimbury (Project B)	Enbridge Gas Inc.	39
30	Bradford West Gwillimbury (Project C)	Enbridge Gas Inc.	46
35	Caledon (Project A)	Enbridge Gas Inc.	207
36	Caledon (Project B)	Enbridge Gas Inc.	100
37	Caledon (Project C)	Enbridge Gas Inc.	141
44	Cedar Springs	Enbridge Gas Inc.	103
58	East Gwillimbury (North and East)	Enbridge Gas Inc.	422
65	Forest Harbour (Tay Twp)	Enbridge Gas Inc.	196
71	Grimsby-Lincoln (Economic Development)	Enbridge Gas Inc.	9
72	Haldimand - Dunnville (Economic Development)	Enbridge Gas Inc.	7
73	Haldimand - Nanticoke (Economic Development)	Enbridge Gas Inc.	9
75	Hamilton - Alberton	Enbridge Gas Inc.	17
76	Hamilton - Rockton	Enbridge Gas Inc.	121
77	Hamilton - Sheffield	Enbridge Gas Inc.	65
78	Hamilton - Westover	Enbridge Gas Inc.	80
79	Hamilton Airport Regional Expansion (Economic Development)	Enbridge Gas Inc.	12
81	Hidden Valley (Huntsville)	Enbridge Gas Inc.	103
90	King Township (Kettleby)	Enbridge Gas Inc.	83
91	King Township (North Nobleton)	Enbridge Gas Inc.	162
98	Limehouse	Enbridge Gas Inc.	63
99	Lisle and Tioga	Enbridge Gas Inc.	367
106	Marsville	Enbridge Gas Inc.	85
125	North Clarington	Enbridge Gas Inc.	398
137	Oro-Medonte	Enbridge Gas Inc.	97
142	Paradise Point	Enbridge Gas Inc.	61
149	Ramara	Enbridge Gas Inc.	1,710
158	Sandford	Enbridge Gas Inc.	140
165	Severn (Project A)	Enbridge Gas Inc.	21
166	Severn (Project B)	Enbridge Gas Inc.	122
167	Severn (Project C)	Enbridge Gas Inc.	723
204	Wilkinson	Enbridge Gas Inc.	89
209	Zephyr, Udora, Leaskdale	Enbridge Gas Inc.	454

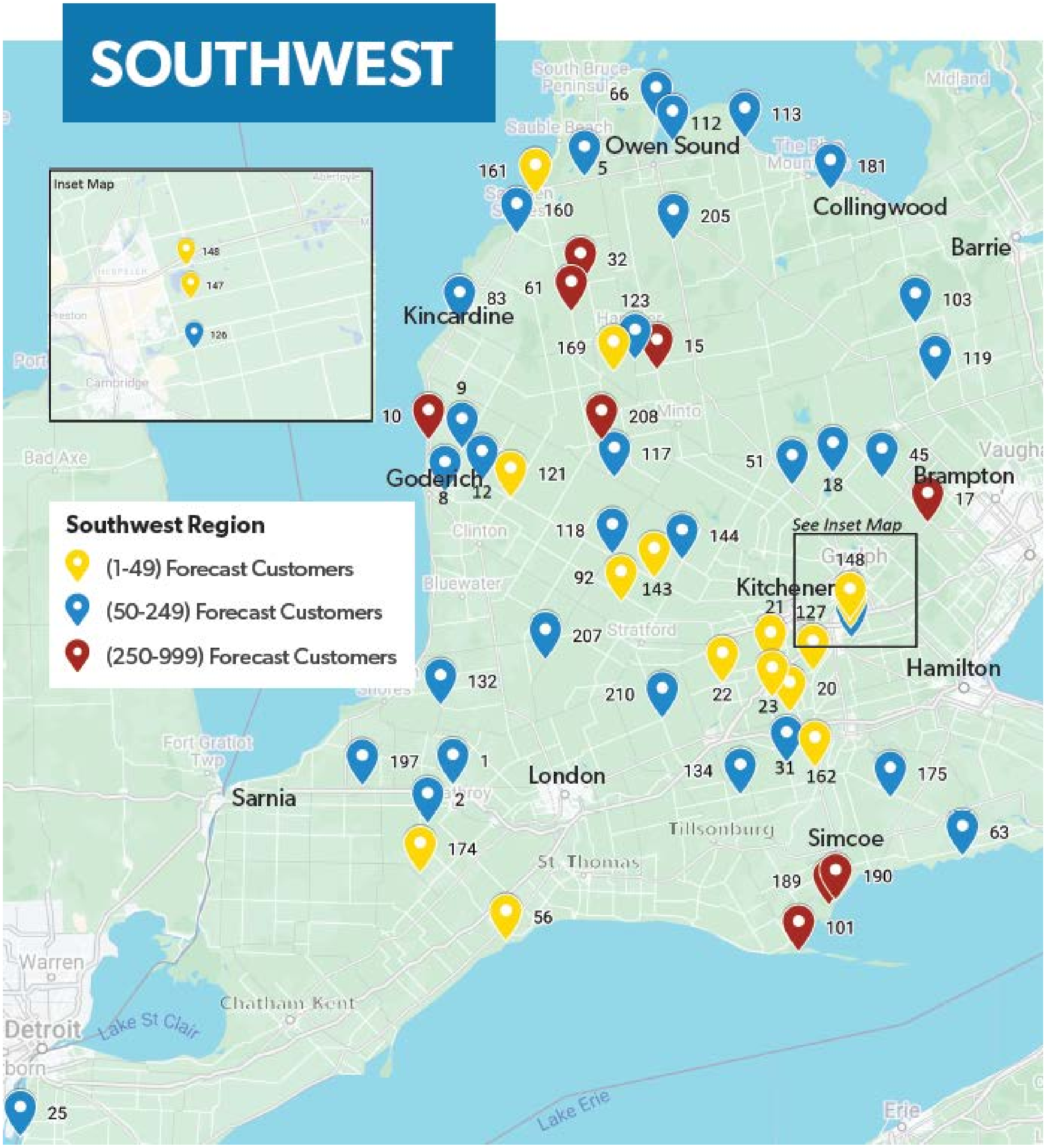
Southeast


SOUTHEAST
Mattawa
Pembroke
Renfrew
Ottawa
Hawkesbury
Cornwall
Smiths Falls
Brockville
Kaladar
Peterborough
Belleville
Cobourg
Kingston
Southeast Region
(1-49) Forecast Customers
(50-249) Forecast Customers
(250-999) Forecast Customers
Over 1000 Forecast Customers

No.	Proposed Project	Proponent	Forecast customers (year 10)
4	Alderville, Roseneath and Alderville FN	Enbridge Gas Inc.	293
6	Ameliasburgh and Rossmore	Enbridge Gas Inc.	778
13	Augusta Township	Enbridge Gas Inc.	47
14	Avonmore, Monkland, Bloomington	Enbridge Gas Inc.	353
16	Bainsville and South Glengarry	Enbridge Gas Inc.	219
24	Bobcaygeon	Enbridge Gas Inc.	3,979
34	Burritts Rapids	Enbridge Gas Inc.	30
38	Camden East, Yarker, Tamworth and Erinsville	Enbridge Gas Inc.	1,022
39	Carlsbad Springs	Enbridge Gas Inc.	444
40	Casselman	Enbridge Gas Inc.	17
41	Cavan Monaghan (Project A)	Enbridge Gas Inc.	75
42	Cavan Monaghan (Project B)	Enbridge Gas Inc.	22
43	Cavan Monaghan (Project C)	Enbridge Gas Inc.	28
47	Chute-à-Blondeau	Enbridge Gas Inc.	318
49	Cornwall Regional Airport	Enbridge Gas Inc.	19
50	Cotnam Island	Enbridge Gas Inc.	93
52	Curran	Enbridge Gas Inc.	106
54	Douglas (Admaston/Bromley)	Enbridge Gas Inc.	153
55	Dunrobin Shores	Enbridge Gas Inc.	458
59	Edwardsburgh Cardinal and Spencerville	Enbridge Gas Inc.	527
60	Eganville	Enbridge Gas Inc.	674
68	Glen Tay (Tay Valley)	Enbridge Gas Inc.	82
69	Glendale	Enbridge Gas Inc.	77
70	Gores Landing	Enbridge Gas Inc.	300
74	Haldimand Shores	Enbridge Gas Inc.	109
86	Kawartha Lakes - Kirkfield, Coboconk and Norland	Enbridge Gas Inc.	946
87	Kawartha Lakes - Scugog	Enbridge Gas Inc.	851
88	Kawartha Lakes - Woodville	Enbridge Gas Inc.	257
93	Lanark and Balderson	Enbridge Gas Inc.	334
95	Laurentian Valley	Enbridge Gas Inc.	201
97	Lefaivre	Enbridge Gas Inc.	246
102	Mallorytown	Enbridge Gas Inc.	375
109	Maxville	Enbridge Gas Inc.	325
114	Merrickville-Wolford	Enbridge Gas Inc.	67
115	Mississippi Mills	Enbridge Gas Inc.	486

No.	Proposed Project	Proponent	Forecast customers (year 10)
116	Mohawks of the Bay of Quinte FN	Enbridge Gas Inc.	126
120	Moose Creek	Enbridge Gas Inc.	396
128	North Dundas (Project A)	Enbridge Gas Inc.	18
129	North Dundas (Project B)	Enbridge Gas Inc.	269
130	North Dundas (Project C)	Enbridge Gas Inc.	183
131	North Grenville	Enbridge Gas Inc.	69
138	Ottawa - Kinburn-Fitzroy Harbour	Enbridge Gas Inc.	445
139	Ottawa - Stittsville	Enbridge Gas Inc.	137
140	Oxford Mills (North Grenville)	Enbridge Gas Inc.	144
141	Papineau-Cameron	Enbridge Gas Inc.	103
145	Prince Edward County (Cherry Valley)	Enbridge Gas Inc.	152
146	Prince Edward County (Consecon and Carrying Place)	Enbridge Gas Inc.	313
156	Roblin & Marlbank	Enbridge Gas Inc.	150
159	Sarsfield	Enbridge Gas Inc.	236
164	Selwyn	Enbridge Gas Inc.	77
170	South Dundas	Enbridge Gas Inc.	125
171	South Stormont (Project A)	Enbridge Gas Inc.	145
172	South Stormont (Project B)	Enbridge Gas Inc.	107
173	South Stormont (Project C)	Enbridge Gas Inc.	27
177	St. Isidore	Enbridge Gas Inc.	386
178	Project 178	Enbridge Gas Inc.	11
184	Thomasburg (Tweed)	Enbridge Gas Inc.	97
191	Tweed	Enbridge Gas Inc.	62
192	Tyendinaga	Enbridge Gas Inc.	409
196	Warsaw	Enbridge Gas Inc.	169
199	Whitewater Region (Project A)	Enbridge Gas Inc.	6
200	Whitewater Region (Project B)	Enbridge Gas Inc.	20
201	Whitewater Region (Project C)	Enbridge Gas Inc.	190
202	Whitewater Region (Project D)	Enbridge Gas Inc.	86
203	Whitewater Region (Project E)	Enbridge Gas Inc.	140
206	Wollaston	Enbridge Gas Inc.	260

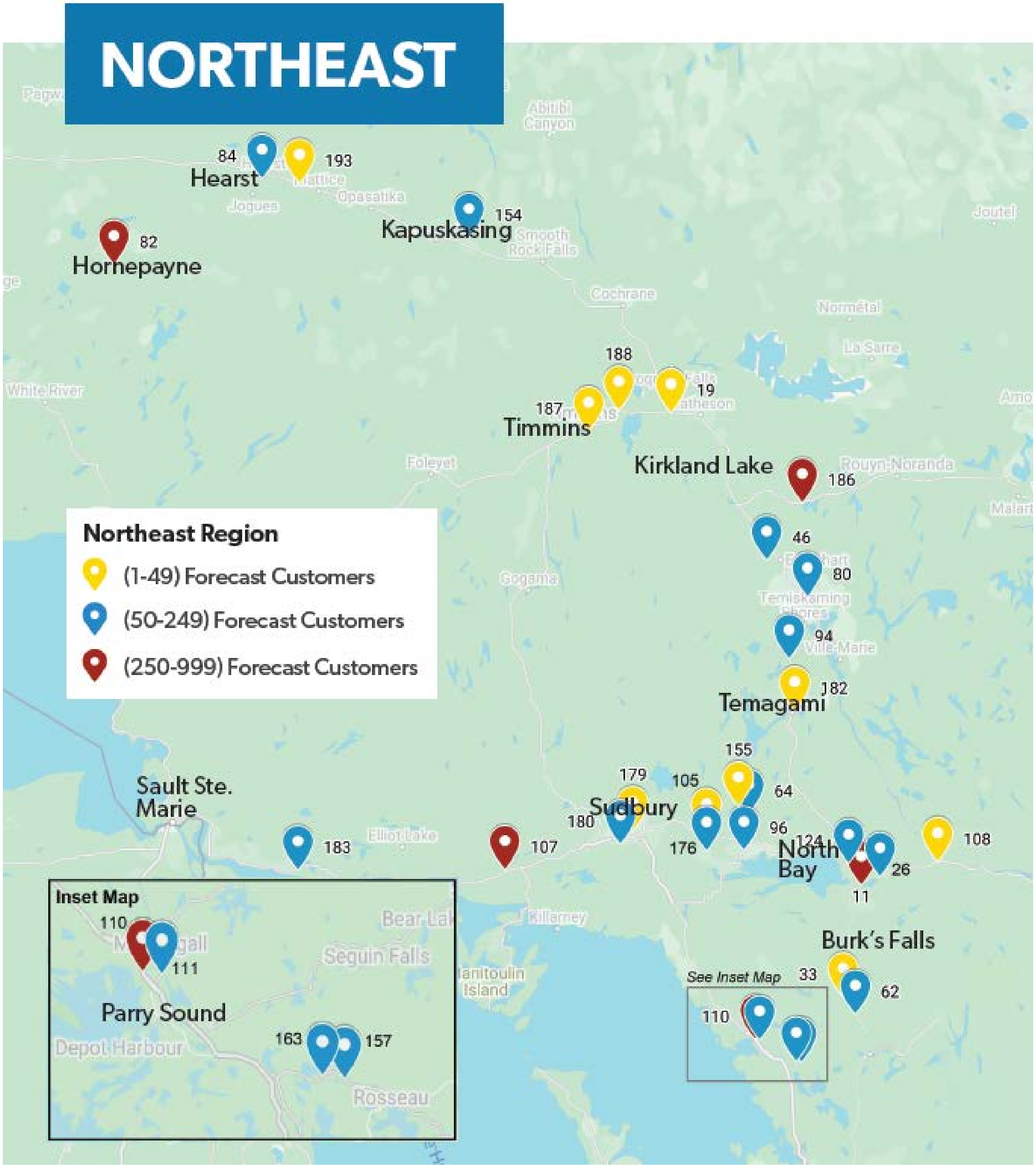
Southwest


SOUTHWEST
Inset Map
148
147
126
Southwest Region
(1-49) Forecast Customers
(50-249) Forecast Customers
(250-999) Forecast Customers
See Inset Map
Owen Sound
Collingwood
Barrie
Kincardine
Goderich
Brampton
Kitchener
Hamilton
London
Sarnia
Simcoe
Detroit
Lake St Clair
Lake Erie
Stratford
Tillsonburg
St. Thomas
Chatham Kent
66
112
113
181
161
5
160
205
32
61
83
123
169
15
103
119
9
10
208
117
51
18
45
17
121
8
12
118
144
92
143
21
127
207
132
210
22
23
20
197
1
2
134
31
162
175
174
63
189
190
56
101
25

No.	Proposed Project	Proponent	Forecast customers (year 10)
1	Adelaide Metcalfe (North)	Enbridge Gas Inc.	79
2	Adelaide Metcalfe (South)	Enbridge Gas Inc.	134
5	Allenford	Enbridge Gas Inc.	118
8	Ashfield-Colborne-Wawanosh - Benmiller	Enbridge Gas Inc.	62
9	Ashfield-Colborne-Wawanosh - Dungannon	Enbridge Gas Inc.	182
10	Ashfield-Colborne-Wawanosh - Dungannon and Port Albert	Enbridge Gas Inc.	276
12	Auburn	Enbridge Gas Inc.	108
15	Ayton and Neustadt	Enbridge Gas Inc.	426
17	Ballinafad and Silver Creek	Enbridge Gas Inc.	290
18	Belwood	Enbridge Gas Inc.	179
20	Blandford-Blenheim - Canning	Enbridge Gas Inc.	26
21	Blandford-Blenheim - Perry’s Corners	Enbridge Gas Inc.	14
22	Blandford-Blenheim - Ratho	Enbridge Gas Inc.	21
23	Blandford-Blenheim - Richwood	Enbridge Gas Inc.	27
25	Boblo Island	Enbridge Gas Inc.	92
31	Brant County – Harley and Glen Morris	Enbridge Gas Inc.	224
32	Brockton	EPCOR	501
45	Cedar Valley	Enbridge Gas Inc.	54
51	Cumnock	Enbridge Gas Inc.	88
56	Dutton Dunwich	Enbridge Gas Inc.	41
61	Elmwood, Chepstow and Cargill (Brockton)	Enbridge Gas Inc.	403
63	Featherstone	Enbridge Gas Inc.	245
66	Georgian Bluffs	Enbridge Gas Inc.	92
83	Huron-Kinloss & Municipality of Kincardine	EPCOR	115
92	Kinkora	Enbridge Gas Inc.	29
101	Long Point (Norfolk County)	Enbridge Gas Inc.	567
103	Mansfield	Enbridge Gas Inc.	243
112	Meaford - Leith	Enbridge Gas Inc.	132
113	Meaford - Sunnyside Beach	Enbridge Gas Inc.	134
117	Molesworth	Enbridge Gas Inc.	54
118	Monkton	Enbridge Gas Inc.	208
119	Mono (Hockley Village)	Enbridge Gas Inc.	196
121	Morris-Turnberry (Walton)	Enbridge Gas Inc.	48
123	Neustadt	Enbridge Gas Inc.	219
126	North Dumfries (Clyde)	Enbridge Gas Inc.	130
127	North Dumfries (Wrigley and Plumtree)	Enbridge Gas Inc.	41
132	North Middlesex	Enbridge Gas Inc.	50

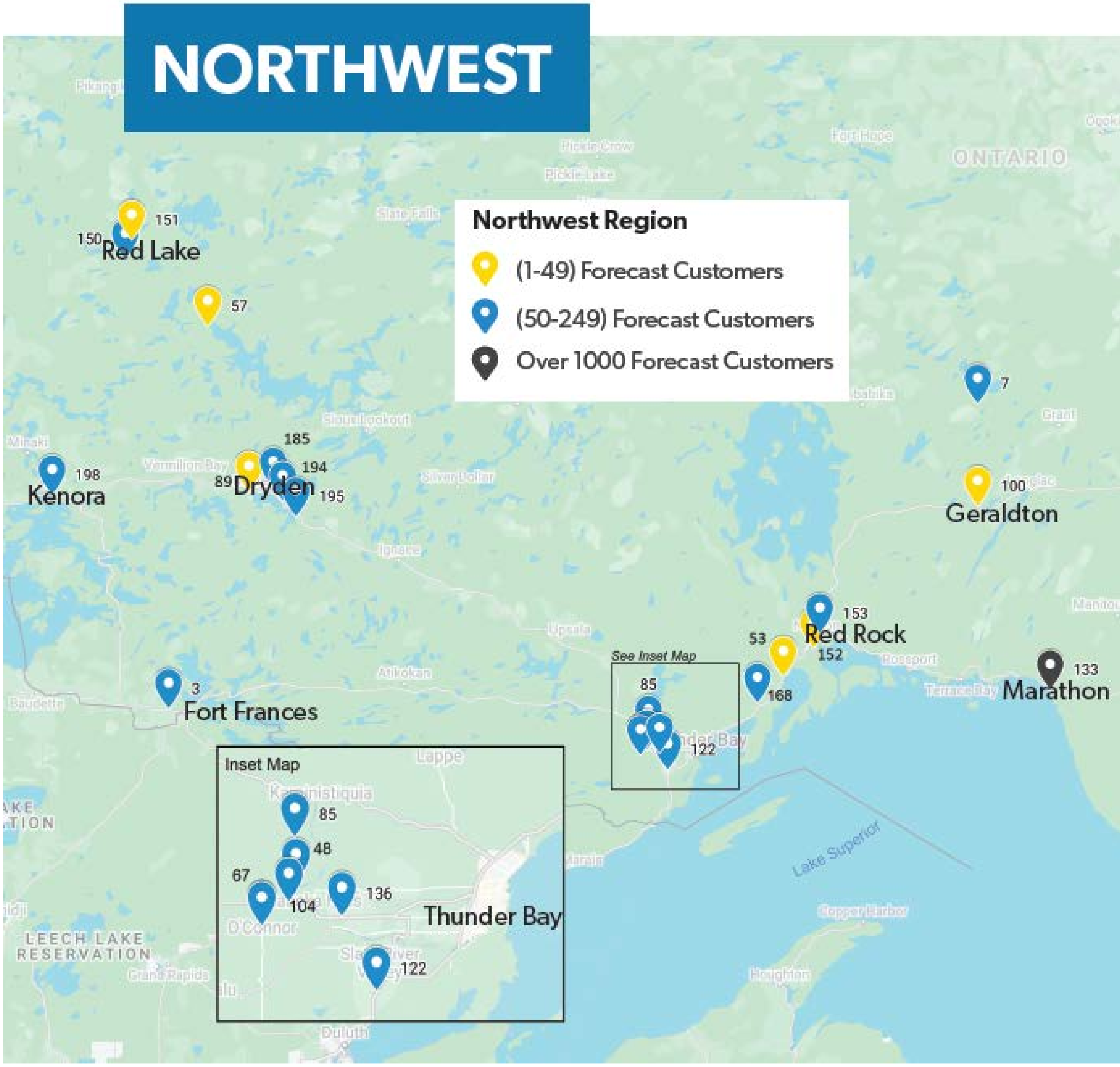
No.	Proposed Project	Proponent	Forecast customers (year 10)
134	Norwich Township	Enbridge Gas Inc.	58
143	Perth East (Brunner)	Enbridge Gas Inc.	44
144	Perth East (Newton and Millbank)	Enbridge Gas Inc.	228
147	Puslinch	Enbridge Gas Inc.	20
148	Puslinch Lake North	Enbridge Gas Inc.	18
160	Saugeen Shores	Enbridge Gas Inc.	80
161	Saugeen Shores - Southampton	Enbridge Gas Inc.	33
162	Scotland	Enbridge Gas Inc.	29
169	South Bruce (Deemerton)	Enbridge Gas Inc.	22
174	Southwest Middlesex	Enbridge Gas Inc.	39
175	Springvale (Haldimand County)	Enbridge Gas Inc.	84
181	Swiss Meadows	Enbridge Gas Inc.	74
189	Turkey Point	Enbridge Gas Inc.	478
190	Turkey Point and Normandale	Enbridge Gas Inc.	537
197	Warwick	Enbridge Gas Inc.	115
205	Williamsford and McCullough Lake	Enbridge Gas Inc.	176
207	Woodham and Kirkton	Enbridge Gas Inc.	132
208	Wroxeter, Gorrie and Fordwich	Enbridge Gas Inc.	560
210	Zorra Township (Kintore)	Enbridge Gas Inc.	131

Northeast


NORTHEAST
Northeast Region
(1-49) Forecast Customers
(50-249) Forecast Customers
(250-999) Forecast Customers
Hearst
Hornepayne
Kapuskasing
Timmins
Kirkland Lake
Temagami
Sault Ste. Marie
Sudbury
North Bay
Burk's Falls
See Inset Map
Inset Map
Parry Sound
84
193
154
82
188
187
19
186
46
80
94
182
155
179
105
64
180
96
124
108
183
107
176
26
11
33
62
110
111
163
157

No.	Proposed Project	Proponent	Forecast customers (year 10)
11	Astorville	Enbridge Gas Inc.	381
19	Black River-Matheson	Enbridge Gas Inc.	37
26	Bonfield	Enbridge Gas Inc.	216
33	Burk's Falls	Enbridge Gas Inc.	41
46	Charlton and Dack	Enbridge Gas Inc.	103
62	Emsdale (Township of Perry)	Enbridge Gas Inc.	185
64	Field	Enbridge Gas Inc.	143
80	Harley	Enbridge Gas Inc.	84
82	Hornepayne	Enbridge Gas Inc.	346
84	Jogues	Enbridge Gas Inc.	58
94	Latchford	Enbridge Gas Inc.	122
96	Lavigne	Enbridge Gas Inc.	61
105	Markstay-Warren	Enbridge Gas Inc.	49
107	Massey, Webbwood, McKerrow	Enbridge Gas Inc.	664
108	Mattawa	Enbridge Gas Inc.	22
110	McDougall (Project A)	Enbridge Gas Inc.	301
111	McDougall (Project B)	Enbridge Gas Inc.	171
124	North Bay / East Ferris	Enbridge Gas Inc.	135
154	Remi Lake (Moonbeam)	Enbridge Gas Inc.	98
155	River Valley (West Nipissing)	Enbridge Gas Inc.	49
157	Rosseau (Township of Seguin)	Enbridge Gas Inc.	244
163	Seguin	Enbridge Gas Inc.	153
176	St. Charles	Enbridge Gas Inc.	162
179	Sudbury (Project A)	Enbridge Gas Inc.	32
180	Sudbury (Project B)	Enbridge Gas Inc.	64
182	Temagami	Enbridge Gas Inc.	11
183	Thessalon First Nation	Enbridge Gas Inc.	63
186	Timiskaming (King Kirkland, Larder Lake, Virginiatown, Kearns) (CNG)	Enbridge Gas Inc.	538
187	Timmins (Project A)	Enbridge Gas Inc.	46
188	Timmins (Project B)	Enbridge Gas Inc.	4
193	Val-Côté	Enbridge Gas Inc.	34

Northwest


NORTHWEST
Northwest Region
(1-49) Forecast Customers
(50-249) Forecast Customers
Over 1000 Forecast Customers
151
150
Red Lake
57
185
194
198
Kenora
89
Dryden
195
7
100
Geraldton
153
Red Rock
53
152
133
Marathon
See Inset Map
85
168
122
3
Fort Frances
Inset Map
85
48
67
104
136
Thunder Bay
122
Lake Superior

No.	Proposed Project	Proponent	Forecast customers (year 10)
3	Alberton	Enbridge Gas Inc.	72
7	Aroland and Nakina	Enbridge Gas Inc.	220
48	Conmee	Enbridge Gas Inc.	126
53	Dorion	Enbridge Gas Inc.	38
57	Ear Falls	Enbridge Gas Inc.	9
67	Gillies and O'Connor	Enbridge Gas Inc.	111
85	Kaministiquia	Enbridge Gas Inc.	151
89	Kenora District	Enbridge Gas Inc.	30
100	Little Longlac	Enbridge Gas Inc.	6
104	Marks Township	Enbridge Gas Inc.	89
122	Neebing	Enbridge Gas Inc.	87
133	North Shore Gas Distribution Project	Lakeshore	3,125
135	O'Connor	Enbridge Gas Inc.	69
136	Oliver Paipoonge	Enbridge Gas Inc.	75
150	Red Lake (Madsen)	Enbridge Gas Inc.	56
151	Red Lake (McKenzie Island)	Enbridge Gas Inc.	40
152	Red Rock	Enbridge Gas Inc.	43
153	Red Rock First Nation (Lake Helen Reserve)	Enbridge Gas Inc.	77
168	Shuniah	Enbridge Gas Inc.	171
185	Thunder Lake and Meadows (Dryden)	Enbridge Gas Inc.	148
194	Wabigoon	Enbridge Gas Inc.	71
195	Wabigoon First Nation	Enbridge Gas Inc.	73
198	Wauzhushk Onigum First Nation	Enbridge Gas Inc.	63

Ontario Energy Board | Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2020-0091

ENBRIDGE GAS INC.

Integrated Resource Planning Proposal

BEFORE: Lynne Anderson
Presiding and Chief Commissioner

Susan Frank
Commissioner

Michael Janigan
Commissioner

July 22, 2021

Ontario Energy Board | Commission de l'énergie de l'Ontario

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1 OVERVIEW

Enbridge Gas filed an application with the OEB which requested that the OEB determine that the policy direction in its Integrated Resource Planning (IRP) proposal was reasonable and appropriate. Integrated resource planning generally refers to a planning process that evaluates and compares both supply-side and demand-side options to meeting an energy system need.

Enbridge Gas indicated that establishing policy guidance for Integrated Resource Planning would enable Enbridge Gas to be successful in considering IRP Alternatives to future facility expansion/reinforcement projects effectively and efficiently. This guidance would also be responsive to previous direction from the OEB that Enbridge Gas should improve its procedures for considering demand-side management as an alternative to pipelines and traditional facility infrastructure.

In response, the OEB is establishing a first-generation IRP Framework that provides direction on the OEB's requirements as Enbridge Gas considers IRP to meet its system needs. The expectation is that enhancements and improvements will be made in the future on the basis of the experience gained in Ontario with pilot projects and other IRP activities, drawing on successes achieved in other jurisdictions, and future policy direction. The IRP Framework is provided in Appendix A to this Decision and Order. Enbridge Gas is expected to begin integrating IRP into its existing planning processes, in a manner consistent with the IRP Framework, effective immediately.

Key elements of the IRP Framework are described below.

Definition of IRP: The IRP Framework establishes the following definition of IRP for Enbridge Gas:

> Integrated Resource Planning is a planning strategy and process that considers Facility Alternatives and IRP Alternatives (including the interplay of these options) to address the system needs of Enbridge Gas's regulated operations, and identifies and implements the alternative (or combination of alternatives) that is in the best interest of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management.

Guiding Principles: The OEB has determined that guiding principles are essential to the establishment of a robust IRP Framework. The IRP Framework cannot anticipate all situations that might occur in the consideration of alternatives to infrastructure builds.

The guiding principles will assist in providing consistent direction for IRP, particularly in these early years. The OEB approves guiding principles for the IRP Framework on reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management. These principles are consistent with the OEB's statutory objectives for natural gas.

Types of IRP Alternatives: The IRP Framework provides guidance on what types of IRP Alternatives Enbridge Gas may consider to meet an identified system need.

Demand-side programming, including geotargeted energy efficiency and demand response programs, is part of the IRP Framework. The demand-side IRP Alternatives are expected to target specific constrained areas and encourage the reduction of peak consumption. The IRP Framework will provide opportunities to gain experience on demand-side programming that focuses on reducing peak demand. Supply-side IRP Alternatives (e.g., compressed natural gas and renewable natural gas, and commercial or market-based alternatives such as peaking supply, third-party assignments, or exchanges), should also be considered, as should storage. For both demand-side and supply-side IRP Alternatives, Enbridge Gas is expected to consider procuring equipment or activities through the competitive market, where feasible and cost-effective.

Enbridge Gas also proposed non-gas IRP Alternatives, specifically electricity-based alternatives. The OEB has concluded that as part of this first-generation IRP Framework, it is not appropriate to provide funding to Enbridge Gas for electricity IRP Alternatives.

IRP Assessment Process: The IRP Framework includes a four-step process Enbridge Gas will use to determine the best approach to meeting system needs, including whether to pursue IRP Alternatives to address an identified need/constraint.

Identification of Constraints: Enbridge Gas will identify potential system needs/constraints up to ten years in the future in its Asset Management Plan, allowing time for a detailed examination of the potential for IRP Alternatives to meet these needs. The Asset Management Plan will provide the status of consideration of IRP Alternatives in regards to meeting system needs, and an updated version will be filed on an annual basis. The first version reflecting this updated process will be filed in Fall 2022.

The OEB is not requiring a more comprehensive review of Enbridge Gas's demand forecasting methodology that is used in identifying system needs at this time. Detailed examination of the ten-year demand forecast methodology is appropriately done at

Enbridge Gas's next rebasing application, at which time the Asset Management Plan will be filed as evidence.

Binary Screening Criteria: The IRP Framework includes screening criteria to select which system needs require further IRP consideration, in order to focus on those situations where there is a reasonable expectation that an IRP Alternative could efficiently and economically meet the need. This will include facility expansion/reinforcement projects where growth is the main driver.

The following criteria will generally exclude a system need from further IRP consideration:

- Emergent safety issues
- System needs that must be met in under three years
- Customer-specific builds where a customer fully pays for the incremental infrastructure costs associated with a facility project
- Community expansion projects driven by government legislation or policy with related funding aimed at delivering natural gas into communities
- Pipeline replacement and relocation projects costing less than the minimum project cost that would necessitate a Leave to Construct approval.

For customer-specific builds and community expansion projects, Enbridge Gas is encouraged to discuss demand-side management opportunities with customers to potentially reduce the size of the build.

Two-stage Evaluation: For system needs progressing past the binary screening, Enbridge Gas will undertake a technical evaluation to first determine if the IRP Alternatives considered can meet the identified need. If so, then Enbridge Gas will compare one or more IRP Plans to the baseline Facility Alternative, using an economic test, to determine the optimum solution to meet the system need.

A three-phase Discounted Cash Flow-plus test, including its focus on rate impacts (as identified in phase 1 of this test), will be the economic evaluation test used in the IRP Framework. This test assesses project benefits and costs from the utility, customer, and societal perspective.

The OEB recognizes that this test could be improved to better list and define the costs and benefits of facility projects and IRP Alternatives, and clarify how these costs and benefits should be considered within the test. Enbridge Gas is expected to study improvements to the Discounted Cash Flow-plus test for IRP, in consultation with the IRP Technical Working Group that will be established as part of the IRP Framework, and using IRP pilot projects as a testing ground. Enbridge Gas shall file an enhanced Discounted Cash Flow-plus test for approval as part of the first non-pilot IRP Plan.

If an IRP Plan is being proposed for the benefit of new customers, the results of the Discounted Cash Flow-plus test will assist the OEB in determining whether the proposed IRP Plan is compatible with the OEB's objective to facilitate rational expansion of transmission and distribution systems. Customer contributions could be applied to reduce cross-subsidization between new and existing customers.

Periodic Review: Enbridge Gas will review its IRP determinations if needed due to changing circumstances and identify any updates as part of an annual IRP report.

Allocation of IRP Risk: There are risks associated with the development of an IRP Plan and the selection of projects to address constraints.

One risk is that the OEB will have limited recourse at the project approval stage (for an IRP Plan or a facility project) if it believes that Enbridge Gas has not chosen the best option to meet a system need, because it may no longer be possible to implement alternative options without compromising safety or reliability. The OEB finds that Enbridge Gas is making considerable effort to improve its planning process, and this is expected to reduce this risk. The OEB is not requiring Enbridge Gas to seek approval for its determinations in the IRP Assessment Process, prior to project-specific applications (for an IRP Plan approval or a Leave to Construct approval). Enbridge Gas has considerable experience with Leave to Construct applications, including circumstances in which conditions of approval or modifications made to the original request have been required by the OEB. Furthermore, the OEB retains the authority to deny recovery of costs if it determines that Enbridge Gas was not prudent in considering alternatives.

A second risk is that an approved IRP Plan may not deliver the load reduction required to address a system need. With regards to who should bear the performance and cost risk associated with approved IRP Plans, the OEB has determined that prudently incurred costs associated with an approved IRP Plan will be eligible for cost recovery. The OEB acknowledges that there may be a greater degree of performance and cost risk associated with IRP Alternatives and IRP Plans in comparison with facility projects, and expects to take this into consideration in its prudence review. However, where Enbridge Gas does not act prudently or not in accordance with an approved IRP Plan, then it may be at risk for recovery of some portion of IRP investments that are deemed imprudent.

A third risk that is a concern for both infrastructure builds and for IRP Alternatives is stranded assets. At this time, the OEB will continue to emphasize the requirement to demonstrate prudence by Enbridge Gas, at both the system planning and project planning levels.

Stakeholder Outreach and Engagement Process: Enbridge Gas will use a three-component stakeholder engagement process for IRP. This will involve: (1) gathering stakeholder insight from existing channels; (2) holding regional stakeholder days on an annual basis focused on system needs identified in the Asset Management Plan and options to address these needs through IRP; and (3) project-specific consultation for specific proposed IRP Alternatives or IRP Plans in a specific geographic region. Enbridge Gas will also establish a website to facilitate the broad sharing of information on IRP stakeholdering efforts.

In addition to the three-component stakeholder process, the OEB will also establish an IRP Technical Working Group led by OEB staff, similar to the current OEB-administered Demand-Side Management Evaluation Advisory Committee. The IRP Technical Working Group will have 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. OEB staff will establish the IRP Technical Working Group, including a terms of reference, and the initial selection of Technical Working Group members, by the end of 2021. The OEB expects that the Technical Working Group’s first priorities will be the consideration and implementation of IRP pilot projects, and enhancements or additional guidance in applying the Discounted Cash Flow-plus evaluation methodology. The IRP Technical Working Group will also be expected to review a draft of Enbridge Gas’s annual IRP report, with the review coordinated by OEB staff. Material concerns that remain unresolved within the Technical Working Group will be brought to the attention of the OEB.

Indigenous Engagement and Consultation: No party has identified any direct material impact the IRP Framework could have on any Aboriginal or treaty rights. The IRP Framework is being established by the OEB following the receipt of input from many stakeholders including an Indigenous representative intervenor.

Enbridge Gas has indicated that it will make efforts to accommodate participation of Indigenous groups within its stakeholder engagement process and work with these groups as appropriate to address any concerns. The OEB endorses this approach.

There is insufficient information on the record at this time to determine which Indigenous communities would be impacted by specific system needs and the potential solutions (IRP Plans or facility projects), and what impact, if any, the individual IRP Plans might have on Aboriginal or treaty rights. In addition to any broader stakeholder engagement with Indigenous groups, Enbridge Gas is required to conduct consultation with respect to any potential impacts to Aboriginal or treaty rights in relation to proposed IRP Plans (which may include the individual IRP Alternatives considered) and Leave to Construct applications. Any concerns can be considered on a case-by-case basis when an IRP Plan or a Leave to Construct application comes before the OEB for approval.

When Enbridge Gas requests approval for an IRP Plan or a Leave to Construct, it will be necessary for Enbridge Gas to follow the requirements in the *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario* regarding Indigenous consultation, if applicable.

Cost Recovery and Accounting Treatment Principles: Costs associated with IRP can fall into three categories: incremental IRP administrative costs, project costs to implement IRP Alternatives, and ongoing operational and maintenance costs to operate and maintain an IRP Alternative after it has been brought into service. Project costs for IRP Alternatives, similar to the costs for infrastructure builds, will be eligible for inclusion in rate base, where Enbridge Gas owns and operates the IRP Alternative. Until rebasing, the associated revenue requirement of these project costs will be recorded in a capital costs deferral account for recovery annually or at rebasing as requested by Enbridge Gas. Where Enbridge Gas proposes to make an enabling payment to a competitive service provider and does not own or operate the asset, these costs, if approved, will be included in the category of ongoing operational and maintenance costs and recovered as operating expenses. Until rebasing, these operating costs will be recorded in an operating costs deferral account for recovery annually or at rebasing as requested by Enbridge Gas. Incremental IRP administrative costs and other ongoing operational and maintenance costs will also be treated as expenses and recorded in this account.

Future IRP Plan Applications: When Enbridge Gas determines that an IRP Alternative (either alone, in combination with other IRP Alternatives, 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 the alternative. The IRP Framework establishes a new OEB approval process for IRP Plans, under section 36 of the *OEB Act*. An IRP Plan approval will endorse the IRP Plan and approve the cost consequences. The OEB expects that an approach to cost allocation will be part of the IRP Plan approval. The costs would then be recovered, subject to a prudence review, through the IRP Costs deferral accounts annually and/or at Enbridge Gas's next rebasing application.

An IRP Plan approval will be mandatory if the forecast costs of the IRP Plan exceed the minimum project cost (currently $2 million, proposed to increase to $10 million) that would necessitate a Leave to Construct approval for a pipeline project. Enbridge Gas is expected to seek approval for an adjustment to an IRP Plan, if any cost adjustment is an increase of greater than 25% of the approved cost. When seeking recovery of actual IRP Plan costs, Enbridge Gas will need to demonstrate that it has been prudent in managing its actions and resulting costs, as is typical for all requests for cost recovery.

Monitoring and Reporting: Enbridge Gas will file an annual IRP report with the OEB as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, with information that includes updates on IRP pilots, potential and approved IRP Plans, and the most recent results of its IRP Assessment Process for system needs, including reporting on those system needs where the assessment ruled out further consideration of IRP Alternatives. The OEB does not intend to approve the annual IRP report, but it could impact the OEB's findings on recovery of the costs in the IRP Costs deferral accounts or inform future proceedings.

IRP Costs Deferral Accounts: The OEB is establishing two IRP Costs deferral accounts for the period from 2021 to 2023, to track incremental IRP-related costs not included in Enbridge Gas's base rates. Enbridge Gas may request disposition of the balances in these accounts, when eligible, as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application.

IRP Pilot Projects: The OEB expects that two IRP pilot projects will be selected and deployed by the end of 2022 as proposed by Enbridge Gas. The pilots are expected to assist in understanding and evaluating how IRP can be implemented to avoid, delay or reduce facility projects. The detailed consideration of IRP pilot projects should commence shortly after the issuance of the IRP Framework with input being sought from the IRP Technical Working Group. The implementation of pilots should not be a barrier to addressing a system need through a non-pilot IRP Plan, if an exceptional time-limited opportunity arises prior to the completion of the pilots.

Advanced Metering Infrastructure: The OEB concludes that there is insufficient information to determine if advanced metering infrastructure is a cost-effective enabler of IRP.

2 THE PROCESS

Enbridge Gas Inc. (Enbridge Gas) originally submitted an Integrated Resource Planning (IRP) proposal to the OEB on November 1, 2019 as part of its Dawn-Parkway System Expansion Project Application (EB-2019-0159).

On April 28, 2020, the OEB issued a Notice of Hearing that initiated a review of Enbridge Gas's IRP proposal as a separate proceeding (EB-2020-0091).

On May 21, 2020, the OEB issued Procedural Order No. 1 that granted intervenor status and cost eligibility, and provided a draft issues list for comment.

The following parties applied for and were granted intervenor status:

- Anwaatin Inc. (Anwaatin)
- Association of Power Producers of Ontario (APPRO)
- Building Owners and Managers Association, Greater Toronto (BOMA)
- Canadian Manufacturers & Exporters (CME)
- The City of Hamilton
- Consumers Council of Canada (CCC)
- Energy Probe Research Foundation (Energy Probe)
- Environmental Defence (ED)
- EPCOR Natural Gas Limited Partnership (ENGLP)
- Federation of Rental-housing Providers of Ontario (FRPO)
- Green Energy Coalition (GEC)
- Independent Electricity System Operator (IESO)
- Industrial Gas Users Association (IGUA)
- London Property Management Association (LPMA)
- Low-Income Energy Network (LIEN)
- Ontario Greenhouse Vegetable Growers (OGVG)
- Ontario Sustainable Energy Association (OSEA)
- Pollution Probe
- School Energy Coalition (SEC)
- The Corporation of the City of Kitchener – Utilities Division (City of Kitchener)
- TransCanada Pipelines Limited (TCPL)
- Vulnerable Energy Consumers Coalition (VECC)

Anwaatin, APPRO, BOMA, CCC, CME, Energy Probe, Environmental Defence, FRPO, GEC, IGUA, LIEN, LPMA, OGVG, OSEA, Pollution Probe, SEC and VECC also applied for and were granted cost eligibility.

On July 15, 2020, the OEB issued a Decision on Issues List and Procedural Order No. 2 that approved a final Issues List, and included provisions for Enbridge Gas and other parties regarding filing additional evidence. On July 22, 2020, Enbridge Gas filed an IRP Study prepared by ICF Canada in support of its application.[1]

In Procedural Order No. 4, issued August 20, 2020, the OEB accepted proposals to file additional evidence submitted by Enbridge Gas, OEB staff, and GEC/ED. In Procedural Order No. 5, issued September 15, 2020, the OEB denied FRPO's proposal to file evidence on supply-side IRP Alternatives, but indicated that supply-side alternatives were in scope of the proceeding, and questions regarding their treatment in the IRP proposal could be put to Enbridge Gas through the interrogatory process.

On October 15, 2020, Enbridge Gas filed additional evidence regarding its IRP proposal, which also included an updated jurisdictional review by ICF Canada of advances of natural gas IRP in other jurisdictions since the completion of the original IRP Study.[2]

The evidence of OEB staff and GEC/ED was filed on November 12, 2020 (the Guidehouse report)[3] and November 23, 2020 (the EFG {Energy Futures Group} report)[4], respectively. The Guidehouse report assessed the IRP experience of natural gas utilities in New York State and its relevance to Ontario. The EFG report made recommendations for IRP in Ontario based on lessons learned from the electricity sector, jurisdictions other than New York State, and natural gas demand-side management programs. Enbridge Gas filed responding evidence regarding these reports on December 11, 2020.

[1] *Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment*, ICF Canada, May 18, 2018
[2] *IRP Jurisdictional Review Report*, ICF Canada, October 14, 2020
[3] *Natural Gas Integrated Resource Planning in New York State and Ontario*, Guidehouse Inc., November 12, 2020
[4] *Best Practices for Gas IRP and Consideration of "Non-Pipe" Alternatives to Traditional Infrastructure Investments*, (Exhibit M2.GEC-ED), Chris Neme, Energy Futures Group, November 23, 2020

Following an interrogatory phase regarding all evidence filed by parties, the OEB held a series of transcribed virtual events in this proceeding, including a Technical Conference on February 10-12, 2021, a Presentation Day on February 19, 2021, and an Oral Hearing on March 1-4, 2021.

Enbridge Gas filed its Argument-in-Chief on March 17, 2021. Intervenors and OEB staff filed final arguments on or before March 31, 2021. All intervenors filed final arguments with the exception of ENGLP, the City of Hamilton, the City of Kitchener, the IESO, and TCPL. Two letters of comment were also received, from Diverso Energy and the Ontario Geothermal Association. Enbridge Gas filed its reply argument on April 21, 2021.

3 APPLICATION SUMMARY

Enbridge Gas originally requested that the OEB determine that the policy direction set out within its IRP proposal is reasonable and appropriate.[5]

In its Argument-in-Chief, Enbridge Gas clarified that it is requesting that the OEB approve an IRP Framework for Enbridge Gas that includes each of the following items:[6]

1) **Guiding Principles**: Approval of Reliability and Safety, Cost Effectiveness, Public Policy and Optimized Scoping as appropriate guiding principles to inform and influence how Enbridge Gas implements IRP.
2) **IRP Proposal Elements**:
   a) **Types of IRPAs**: Approval for Enbridge Gas to use a wide variety of demand side alternatives (gas and non-gas, including electricity-based solutions), along with appropriate supply side alternatives, to meet an identified need/constraint (including allowing for consideration of a variety of ownership, operation and/or procurement scenarios for each).
   b) **IRP Assessment Process:** Approval of a prescribed process, consisting of the four steps described below, to determine whether to pursue IRP solutions for an identified need/constraint.
      i) *Identification of Constraints*: Enbridge Gas's asset management process will identify potential system needs/constraints up to ten years in the future and describe these in annual updates to the Asset Management Plan (AMP).
      ii) *Binary Screening Criteria:* Enbridge Gas will apply five binary screening criteria to identified system needs/constraints in the AMP to determine whether further IRP evaluation is appropriate.
      iii) *Two-Stage Evaluation Process:* Where a project progresses past the initial binary screening, Enbridge Gas will determine whether to proceed with an IRP Plan through two stages. First, Enbridge Gas will determine whether potential IRPAs could meet the identified constraint need. If yes, then Enbridge Gas will compare one or more IRP Plans to the baseline Facility Alternative, using a DCF+ {Discounted Cash Flow +} test, to determine the optimum alternative.
      iv) *Periodic Review:* Where circumstances change (for example, the nature or timing of an identified need/constraint alters materially, or significant policy changes are announced by government or the OEB), then Enbridge Gas will

[5] Exhibit A, Tab 13, p. 1
[6] Argument-in-Chief, pp. 13-15

review its IRP determinations related to identified needs/constraints (reflecting changes through the annual update to the AMP) and will report to the OEB, stakeholders and potentially affected Indigenous groups as appropriate (either through the AMP, the IRP Report or via an IRPA application).

c) **Stakeholder Outreach and Engagement Process:** Approval of the proposed three-component stakeholdering process, including a purpose-specific stakeholder Technical Working Group to support IRPA development and to identify and discuss new IRP solutions and IRP avoided costs and benefits.
d) **IRPA Cost Recovery and Accounting Treatment Fundamentals:** Approval of like-for-like treatment of IRPA investments, such that longer term investments in IRPA Plans will be capitalized as rate base, with cost recovery similar to the facility investments that they are replacing at the time of in-service (with IRPA costs amortized over their useful lives).
e) **Future IRP Plan Applications:** Approval of a process similar to the Leave to Construct approval process, to review and approve a proposed IRP Plan designed to meet an identified need/constraint, with Enbridge Gas being given flexibility to adjust the IRP Plan without further OEB review except where the costs being adjusted are an increase of 25% or greater of the total approved cost.
f) **Monitoring and Reporting:** Approval of the proposed annual IRP reporting from Enbridge Gas that will address IRP integration into existing planning processes, IRPA effectiveness, IRP pilot projects planned or underway, IRP stakeholdering and IRPA implementation.

3) **IRP Costs Deferral Account:** Approval of an IRP Costs deferral account which will track all incremental IRP-related costs not included in base rates (capital, operating and administrative costs) during the current deferred rebasing term.
4) **IRP Pilot Project Proposal:** Approval for Enbridge Gas to develop two pilot projects to be developed and initiated by the end of 2022 – one of which will apply the new IRP Framework through development and implementation of an IRP Plan to meet an identified need/constraint and the other of which will test a promising IRPA such as Demand Response, along with Advanced Metering Infrastructure (AMI), if possible.
5) **AMI Acknowledgement:** An indication of the OEB’s support for the role of AMI as an important enabler of successful IRP and IRPAs.

4 STRUCTURE OF THE DECISION

The Decision and Order follows the format of Enbridge Gas's Argument-in-Chief, and the specific approvals requested by Enbridge Gas as part of the IRP Framework. In addition, the Decision and Order includes two chapters on issues that are relevant to the IRP Framework but do not address specific approvals requested by Enbridge Gas, regarding Indigenous engagement and consultation, and IRP-related risk. Appendix A provides the approved first-generation IRP Framework, consistent with the findings in the Decision and Order.

5 IRP FRAMEWORK AND DEFINITION OF IRP

This chapter discusses the need for, and form of, an Integrated Resource Planning (IRP) Framework for Enbridge Gas, and the definition of IRP within such a Framework.

Within the energy sector generally, integrated resource planning usually refers to a planning process that evaluates and compares both supply-side and demand-side options for meeting an energy system need, and may also refer to consideration of multiple energy sources, and co-ordination or integration between multiple energy service providers.

In the context of Enbridge Gas's operations, prior to Enbridge Gas's IRP application, the OEB had previously considered the role of both supply-side and demand-side options for meeting the system needs of Enbridge Gas (and its predecessors, Enbridge Gas Distribution and Union Gas), and more specifically the potential for natural gas demand-side management (DSM) to defer or avoid capital investments in natural gas infrastructure, in several Leave to Construct decisions, and in the OEB's oversight of natural gas DSM. The following table provides examples of these previous considerations.

Table 1: Previous OEB Consideration of Integrated Resource Planning For Enbridge Gas

Date	Initiative	Proceeding
January 30, 2014	OEB issues Decision and Order on GTA-Parkway Project, which concludes that further examination of natural gas IRP is warranted, and provides guidance regarding assessment of demand-side alternatives in Leave to Construct applications	EB-2012-0451 EB-2012-0433 EB-2013-0074
December 22, 2014	OEB issues 2015-2020 DSM Framework, which includes infrastructure deferral as one of the goals of DSM	EB-2014-0134
January 20, 2016	OEB issues Decision and Order on EGD/Union 2015-2020 DSM plans, which directs EGD and Union to work jointly on a transition plan that outlines how to include DSM as part of future infrastructure planning activities	EB-2015-0029 EB-2015-0049

January 15, 2018	Enbridge Gas Distribution files IRP transition plan, and study from ICF Canada, as part of mid-term review of DSM framework	EB-2017-0127 EB-2017-0128
November 29, 2018	OEB issues report on mid-term review of DSM framework, which indicates that natural gas utilities should include a comprehensive evaluation of conservation and energy efficiency as an alternative to reduce or defer infrastructure investments as part of all leave to construct applications	EB-2017-0127 EB-2017-0128
January 3, 2019	OEB issues Decision and Order on EGD's Bathurst Reinforcement Leave to Construct application, finding that EGD's process for considering DSM as a viable alternative to this Project was not appropriate	EB-2018-0097
November 1, 2019	Enbridge Gas files IRP proposal as part of Dawn-Parkway Expansion Leave to Construct Application	EB-2019-0159

Enbridge Gas indicated that it filed its original IRP proposal for three reasons:[7]

1) To be responsive to recent direction from the OEB to: (a) consider demand-side management (DSM) as a pipeline alternative at the preliminary stage of project development in the context of leave to construct applications, (b) develop more rigorous, robust and comprehensive procedures to ensure conservation and energy efficiency opportunities can be reasonably considered as alternatives to future capital projects, as requested by the OEB in its Report on the DSM Mid-Term Review.[8]

2) To establish the necessary IRP policy guidance required for Enbridge Gas to be successful in considering IRP Alternatives (IRPAs) as non-facility alternatives to future expansion/reinforcement projects effectively and efficiently.

3) To demonstrate that IRP was not a viable alternative to the proposed Dawn-Parkway

[7] Exhibit A, Tab 13, p. 2
[8] *Report of the Ontario Energy Board - Mid-Term Review of the DSM Framework for Natural Gas Distributors (2015-2020)*, November 29, 2018, pp. 20-21

System Expansion project.

Enbridge Gas's application for the proposed Dawn-Parkway System Expansion project has been withdrawn and is no longer before the OEB.[9] However, the first two reasons noted by Enbridge Gas for considering Enbridge Gas's IRP proposal remain relevant to the current application.

Need for, and Form of, IRP Framework

In its original application, Enbridge Gas requested that the OEB determine that the policy direction set out within its IRP proposal is reasonable and appropriate.[10] In its Argument-in-Chief, Enbridge Gas requested that, "as part of the IRP Framework that will be issued by the OEB", the OEB consider and approve specific elements of its proposal.[11]

Several parties (FRPO, OEB staff, Pollution Probe, SEC) argued that consideration of different options to meet system needs is already an obligatory activity for Enbridge Gas, regardless of whether there is an IRP Framework in place, although a Framework may provide more detail on specific aspects.

However, most parties (including those above except for SEC) agreed that an IRP Framework was desirable to guide Enbridge Gas's consideration of alternatives in system planning.

Parties generally used Enbridge's IRP proposal as the starting point to frame their submissions regarding the content of the IRP Framework, with varying degrees of differentiation from Enbridge's IRP proposal. Only SEC argued that Enbridge's IRP proposal should be rejected outright;[12] however, SEC proposed an alternative approach to IRP, not a rejection of the principle that Enbridge Gas needs to consider different options to meeting system needs.

There was a range of views as to how detailed an IRP Framework should be. Energy Probe and Pollution Probe argued that more detail was needed, but other parties (LPMA, SEC) expressed caution about overly pre-determining or constraining Enbridge Gas's approach to IRP, in the absence of specific IRPAs or a system plan developed with consideration of IRPAs in mind. OEB staff recommended that the IRP Framework

[9] EB-2019-0159, Procedural Order No. 8, November 18, 2020
[10] Exhibit A, Tab 13, p. 1
[11] Argument-in-Chief, pp. 12-15
[12] SEC Argument, p. 8

be high-level in nature, to recognize that the details of Enbridge Gas's approach to IRP will evolve based on the learnings acquired in the initial years of the Framework. OGVG suggested that the OEB make clear that the development of an IRP Framework is expected to be an iterative process.

Definition and Scope of IRP for Enbridge Gas

As part of its Argument-in-Chief, Enbridge Gas proposed two potential definitions of IRP as it would apply to Enbridge Gas, that could be adopted for the IRP Framework as follows:[13]

- IRP is a multi-faceted planning process that includes the identification, evaluation and implementation of realistic natural gas supply-side and demand-side options (including the interplay of these options) to determine the solution to an identified future need or constraint that provides the best combination of cost and risk for Enbridge Gas customers.
- IRP is aimed at considering facility and non-facility alternatives to address long-term system constraints/needs such that an optimized and economic solution is proposed and implemented to meet the identified constraint or need.

While there are minor differences between these proposed definitions, both frame IRP as a planning process driven by the system needs of Enbridge Gas's operations, considering different options to meet these system needs, and determining the best approach to meet these needs.

OEB staff proposed a similar definition:

> Integrated Resource Planning is a planning strategy and process that considers facility and non-facility alternatives (including the interplay of these options) to address the system needs of Enbridge Gas's regulated operations, and identifies and implements the alternative (or combination of alternatives) that is in the best interest of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, risk minimization, planning and regulatory efficiency, stakeholder perspectives, and alignment with public policy objectives.[14]

Most parties accepted Enbridge Gas's definition or proposed similar definitions.

[13] Argument-in-Chief, p. 6
[14] OEB Staff argument, p. 15

One area where parties' views differed was whether the scope and definition of IRP should be limited to Enbridge Gas's operations or should require more integrated energy planning with other energy providers.

Parties such as OGVG, Energy Probe and IGUA argued that the IRP Framework should be drafted and scoped with regards to the OEB's legislated objectives for natural gas[15] and the OEB's responsibilities under the OEB Act for regulation and oversight of natural gas distribution, transmission, and storage. Energy Probe submitted that consideration of broad energy planning is a policy issue for the Ontario government to consider and provide direction to the OEB and Enbridge Gas as necessary.

Other parties argued that this framing was too narrow in scope, both in the context of an expected energy transition to lower-carbon energy sources in the coming years, and a desire to meet Ontario's energy needs in the most efficient way possible. LPMA proposed a definition for IRP as an "energy sector wide planning process that evaluates and compares all available energy demand-side and supply-side options."[16], which would extend to maximizing the utilization of both natural gas and electricity assets, as part of the energy transition.

FRPO objected to Enbridge Gas's reference to "long-term system constraints/needs" within its definition of IRP, submitting that IRP can also encompass bridging mechanisms that are short- and medium-term solutions. Pollution Probe also defined IRP as being inclusive of short- and medium-term planning decisions.

Findings

The OEB acknowledges and thanks the many parties who participated in this proceeding. The parties provided diverse perspectives as to how to proceed with the development of alternatives to infrastructure builds. The studies by ICF Canada, Energy Futures Group and Guidehouse assisted the OEB in understanding the progress of IRP in other jurisdictions, and were taken into consideration in developing the IRP Framework. IRP in the natural gas sector has been initiated in only a few jurisdictions, and where work is underway it appears to still be in early stages.

[15] OEB Act, s.2
[16] LPMA Argument, p. 2

Need for, and Form of, IRP Framework

Some parties submitted that it was premature to develop an IRP Framework, while others suggested that a detailed and comprehensive IRP Framework would allow for more efficient developments to replace infrastructure construction. The OEB has concluded that given the direction in many OEB decisions over the years requiring Enbridge Gas to undertake a more thorough consideration of alternatives, the OEB must provide direction on the approvals Enbridge Gas requested and respond to the issues raised by several parties, in an IRP Framework. The OEB is establishing a first-generation IRP Framework with the expectation that enhancements and improvements will be made in the future on the basis of the experience gained in Ontario with pilot projects and other IRP activities, drawing on successes achieved in other jurisdictions, and future policy direction. A first-generation IRP Framework including applicable definitions is provided in Appendix A. The Framework is a companion document to this Decision and Order regarding IRP for Enbridge Gas.

The IRP Framework provides direction to Enbridge Gas on topics to be covered in an IRP Plan and the OEB's requirements as Enbridge Gas considers and develops IRP Plans to meet its system needs. If Enbridge Gas has reasons for a specific IRP Plan to deviate from the Framework, it should justify why deviations from the Framework requirements are appropriate.

The IRP Framework has been established for Enbridge Gas; however, it should also be used as a resource to guide EPCOR Natural Gas Limited Partnership (ENGLP) when it examines infrastructure investments and potential alternatives. The OEB expects that this IRP Framework for Enbridge Gas will be a starting point for consideration of an IRP Framework that would be appropriate for ENGLP.

How the IRP Framework will address the specific elements of Enbridge Gas's IRP proposal is discussed in subsequent chapters of this Decision and Order.

Definition and Scope of IRP for Enbridge Gas

The OEB finds that the OEB staff definition of IRP is a generally sound basis on which to develop this first-generation IRP Framework.

The OEB is establishing the following definition of IRP.

> Integrated Resource Planning is a planning strategy and process that considers Facility Alternatives and IRP Alternatives (including the interplay of these options) to address the system needs of Enbridge Gas's regulated operations and identifies and implements the alternative (or combination of alternatives) that is in the best interest of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management.

Some parties suggested that IRP should be focused on energy requirements and not just natural gas. The OEB agrees with Enbridge Gas that this first-generation IRP Framework should focus on the needs of its natural gas customers. Natural gas investment planning is already very complex, and it is premature to attempt to move to integrated energy planning or attempt to anticipate the future energy transition. Work is underway on an update to Ontario's long-term energy planning framework[17] which might provide policy direction regarding the integration of gas and electricity in assessing energy options.

The OEB has established other definitions which are necessary to the IRP Framework. These are similar to the definitions used by the OEB in its Decision on Issues List and Procedural Order No. 2,[18] but have been updated to be consistent with the details of the final IRP Framework.

- **IRP Assessment Process:** The process used by Enbridge Gas to determine the preferred solution to meet specific system needs, including consideration of Facility Alternatives and IRP Alternatives.
- **Facility Alternative:** A potential infrastructure solution considered under the IRP Assessment Process in response to a specific system need of Enbridge Gas. In this IRP Framework, the term is synonymous with a traditional or conventional facility project. This would typically include a hydrocarbon line (as defined in the *OEB Act*) developed by Enbridge Gas, and ancillary infrastructure. Facility Alternatives determined by Enbridge Gas to be the preferred solution to meet the system need will often require approval from the OEB through a Leave to Construct application. For clarity, non-traditional solutions to system needs that include infrastructure developed by Enbridge Gas, such as injection of

[17] Environmental Registry notice ERO 019-3007, January 27, 2021
[18] Decision on Issues List and Procedural Order No.2, July 15, 2020, p. 6

compressed or renewable natural gas, or storage of natural gas within the distribution or transmission system, are considered to be IRP Alternatives and not Facility Alternatives.

- **IRP Alternative (IRPA):** A potential solution other than a Facility Alternative considered in Enbridge Gas's IRP Assessment Process in response to a specific system need of Enbridge Gas. IRPAs determined by Enbridge Gas to be the preferred solution to meet the system need (alone, in combination with other IRPAs, or in combination with a Facility Alternative) would likely be brought forward for approval from the OEB through an IRP Plan.

- **IRP Plan:** A plan filed by Enbridge Gas for OEB approval in response to a specific system need, that includes one or more IRPAs.

6 GUIDING PRINCIPLES

Enbridge Gas requested "approval of reliability and safety, cost effectiveness, public policy and optimized scoping as appropriate guiding principles to inform and influence how Enbridge Gas implements IRP."[19]

Enbridge Gas indicated that approved guiding principles for IRP would be valuable in providing direction and guidance in the implementation of IRP Plans, and in determining how to deal with unforeseen items. Enbridge Gas submitted that, individually and collectively, its proposed guiding principles were consistent with the OEB's statutory objectives in relation to natural gas.[20]

Specific Guiding Principles

Enbridge Gas proposed the following wording for these guiding principles[21]:

- Reliability and Safety - In considering IRPAs as part of system planning processes, Enbridge Gas's system design principles cannot be compromised, and the reliable and safe delivery of firm contracted peak period natural gas volumes to Enbridge Gas's customers must remain of paramount importance.
- Cost Effectiveness – IRPAs must be cost-effective (competitive) compared to other facility and non-facility alternatives, including taking into account impacts on Enbridge Gas ratepayers.
- Public Policy – IRP will be considered in a manner to ensure that it is supportive of and aligned with public policy, where appropriate.
- Optimized Scoping - Recognizing that reviewing IRPAs for every forecasted infrastructure project would be extremely time intensive, binary screening should be undertaken to confirm which forecast need(s) should undergo an IRP assessment and to ensure a focus at the outset on efficient and effective IRPA investment.

Most parties commenting on this issue agreed with the importance of establishing guiding principles for the IRP Framework, with the exception of Pollution Probe.[22]

[19] Argument-in-Chief, p. 13
[20] OEB Act, s.2
[21] Argument-in-Chief, p. 6
[22] Pollution Probe recommended the guiding principles be rejected in favour of establishing foundational objectives of increased accountability, increased transparency and performance measurement.

Commenting parties supported the proposed guiding principles on reliability and safety,[23] and on cost-effectiveness.

On the proposed guiding principle on public policy, CME submitted that the relevant public policy goals should be taken from the OEB's statutory objectives, a position which was supported by Enbridge Gas. GEC suggested rewording this guiding principle to require "Alignment with other governmental policy objectives", which Enbridge Gas did not support, stating that this could lead to confusion as to what "other" government policies are relevant, and which are paramount.[24]

Parties expressed some concerns with Enbridge Gas's proposed guiding principle on optimized scoping. Parties generally agreed that some form of scoping was necessary, but expressed concerns regarding how this principle might be applied in practice to unduly screen out potential IRPAs.

OEB staff proposed to broaden and modify the optimized scoping guiding principle to:

- Planning and Regulatory Efficiency - To focus on efficient and effective IRPA investment, resources are allocated to IRP activities in proportion to their expected impact, at all steps of IRP.

In addition to the guiding principles proposed by Enbridge Gas, several parties proposed additional guiding principles.

OEB staff and GEC both proposed a principle on risk minimization, which included minimizing the economic risk associated with meeting system needs and reliability requirements.[25] OEB staff's proposed principle also indicated that risks and rewards are to be allocated appropriately between Enbridge Gas and its customers.

OEB staff proposed a new principle on stakeholder perspectives, such that "IRP takes into consideration the perspectives of stakeholders regarding how best to meet system needs, including the perspectives of stakeholders and potentially affected Indigenous groups from the specific geographic area relevant to a system need".

FRPO proposed a guiding principle regarding procedural fairness and reasonableness, to ensure evaluation of IRPAs was conducted on a level playing field, which could

[23] FRPO supported the proposed guiding principle of reliability and safety, but expressed concern that this should not be used selectively to bias utility ownership of assets over reliable third-party assets.
[24] Enbridge Gas Reply Argument, p. 26
[25] GEC's proposed principle also noted reliability risk.

include stakeholders seeking the OEB’s assistance to obtain information from Enbridge Gas if required. Enbridge Gas expressed concern that unencumbered access to any and all utility information would lead to additional regulatory burden.

Finally, GEC proposed three additional guiding principles: “equitable consideration of all viable resource options”, “alignment of utility interests with IRP goals” and “timely and accountable assessment of alternatives”.

Findings

The OEB approves the adoption of guiding principles for the IRP Framework on reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management. These principles are consistent with the OEB’s statutory objectives for natural gas.

The OEB has determined that guiding principles are essential to the establishment of a robust IRP Framework. The IRP Framework cannot anticipate all situations that might occur in the consideration of alternatives to infrastructure builds. The guiding principles will assist in consistent direction for IRP, particularly in these early years. Similarly, Enbridge’s Gas Supply Plan is underpinned by guiding principles that inform the creation and assessment of that plan. IRP Plans filed with the OEB should include a section to discuss how these guiding principles have been addressed.

The OEB concludes that there is widespread support for the guiding principles that address reliability/safety and cost effectiveness.

The OEB finds that the guiding principle for public policy should be driven by the OEB’s statutory objectives and provincial and federal laws and regulations. While Enbridge Gas and the OEB may also consider other relevant provincial and federal policies, it is acknowledged that the OEB’s statutory objectives must have primacy in the event of any conflict with such policies.

The OEB concludes that it is appropriate to include Enbridge Gas’s proposed optimized scoping principle in the guiding principles. The optimized scoping principle is directed to establishing an efficient process, which the OEB agrees is essential particularly at this early stage of implementation. Further discussion of concerns regarding how Enbridge Gas will apply this principle in practice will be addressed in section 8.2 (“Binary Screening Criteria”). The addition of effectiveness proposed by OEB staff can be covered under the guiding principle on cost-effectiveness.

OEB staff and GEC proposed to add a guiding principle on risk minimization. Concern was raised by Enbridge Gas that the risk of IRPAs can be materially different from the risk of an infrastructure build. With experience in implementing IRPAs, Enbridge Gas will be better equipped to assess the risk and to take mitigating actions for IRPAs. The issue of who should bear the risk also received considerable attention. At a strategic level, the OEB recognizes the IRPAs could have different risk profiles and concludes that it is appropriate for the IRP Framework to include a principle on risk management, similar to the risk minimization principle proposed by OEB staff:

- Risk management - Economic risks associated with both Facility Alternatives and IRPAs in meeting system needs are evaluated and appropriately mitigated. Risks and rewards are allocated appropriately between Enbridge Gas and its customers.

The allocation of IRP risks is discussed in chapter 9 ("Allocation of IRP Risks"). Aside from this principle on risk management, the OEB has determined that additional guiding principles proposed by OEB staff, FRPO, and GEC are not required.

OEB staff proposed to add a guiding principle on stakeholder perspectives. The OEB considers stakeholdering an important element of the IRP process. However, it does not require a separate guiding principle.

Regarding FRPO's proposed guiding principle on procedural fairness and reasonableness, the IRP Framework must ensure that stakeholders have an opportunity to participate in an effective manner. Therefore, this proposed guiding principle is not required.

Regarding the three additional principles proposed by GEC, the OEB finds that while these are all relevant considerations, they are best handled as part of specific elements of the IRP Framework rather than being established as guiding principles. These topics will be considered further when the proposed elements of the IRP Framework are discussed.

The final guiding principles are as follows:

- Reliability and safety – In considering IRPAs as part of system planning processes, Enbridge Gas's system design principles cannot be compromised, and the reliable and safe delivery of firm contracted peak period natural gas volumes to Enbridge Gas's customers must remain of paramount importance.

- Cost-effectiveness – IRPAs must be cost-effective (competitive) compared to Facility Alternatives and other IRPAs, including taking into account impacts on Enbridge Gas customers.
- Public policy – IRP will be considered in a manner to ensure that it is supportive of and aligned with public policy, and in particular the OEB's statutory objectives for the natural gas sector.
- Optimized scoping – Recognizing that reviewing IRPAs for every forecast infrastructure project would be extremely time intensive, binary screening should be undertaken, to confirm which forecast need(s) should undergo evaluation of IRPAs, and to ensure a focus at the outset on efficient and effective IRPA investment.
- Risk management – Economic risks associated with both Facility Alternatives and IRPAs in meeting system needs are evaluated and appropriately mitigated. Risks and rewards are allocated appropriately between Enbridge Gas and its customers.

7 TYPES OF IRPAS

Enbridge Gas requested approval for Enbridge Gas to use a wide variety of IRPAs to meet an identified need/constraint (including allowing for consideration of a variety of ownership, operation and/or procurement scenarios).[26]

The range of IRPAs Enbridge Gas proposed[27] included gas supply-side alternatives (such as compressed natural gas and renewable natural gas, and commercial or market-based alternatives such as peaking supply, third-party assignments, or exchanges), demand-side alternatives (demand response and targeted energy efficiency, gas-fired heat pumps), and non-gas alternatives, in particular, electricity (e.g. geothermal, electric heat pumps) and potentially district energy and power-to-gas. All of these have the potential to address system needs by reducing peak demand in constrained areas of the natural gas distribution or transmission system.

Demand-side IRPAs:

In its initial IRP proposal, Enbridge Gas submitted that IRP should be reviewed and treated separately from its DSM Plan, although Enbridge Gas did not request a specific approval on this topic as part of its Argument-in-Chief in this IRP proceeding. The impact of activity in Enbridge Gas's DSM Plans is already incorporated into Enbridge Gas's demand forecasts, which then informs identification of system needs; however, Enbridge Gas indicated that active use of demand-side solutions in the context of infrastructure planning should be done through the IRP Framework, not the DSM Plan. In a letter dated December 1, 2020, the OEB invited Enbridge Gas to file a new multi-year DSM plan for the post-2021 period. This letter indicated that the OEB would decide on the relationship between the IRP Framework and utility DSM plans in this IRP proceeding, including the extent to which Enbridge Gas will be expected to meet the objective of creating opportunities to actively defer or avoid infrastructure projects within its DSM plan.[28] Subsequently, Enbridge Gas has filed an application for its next DSM Plan (2022 to 2027), which is currently before the OEB and does not include any geotargeted energy efficiency programming, pending any direction arising from the IRP Framework.[29]

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[26] Argument-in-Chief, p. 16
[27] Exhibit B, pp. 21-29, Argument-in-Chief, p. 18
[28] OEB Letter, Re: Post-2020 Natural Gas Demand Side Management Framework, December 1, 2020
[29] Multi-Year Demand Side Management Plan (2022 to 2027), EB-2021-0002, Application and Evidence, Exhibit C, Tab 1, Schedule 2

Within the IRP Framework, Enbridge Gas proposed that demand-side solutions considered as IRPAs could include enhanced targeted energy efficiency programs and demand response programs. Enhanced targeted energy efficiency programs would focus on achieving a high penetration in a specific geographical area to reduce peak period system demands. This could include supplemental targeted funding or incentives to customers in constrained areas for existing energy efficiency programs that are already offered franchise-wide through the DSM Plan, or entirely new energy efficiency programs, including efficiency measures such as gas-fired heat pumps.

Demand response programs are designed to incent or oblige the customer to reduce or shift energy usage during peak periods. They can be controlled by the utility or the customer and can be voluntary or contractually binding. Demand response programs are well-established in the electricity sector, and natural gas demand response programs are being undertaken by utilities pursuing IRP in New York State.

Somewhat similar in nature to demand response programs are interruptible rates. Customers on interruptible rates pay a lower rate in exchange for the ability of Enbridge Gas to curtail delivery if capacity is not available on the system. Interruptible volumes are not included in Enbridge Gas's design day assumptions. Therefore, increased use of interruptible rates could potentially reduce the amount of firm peak demand Enbridge Gas is obligated to serve, helping address a system need. For this reason, Enbridge Gas indicated that it does consider interruptible rates to be a type of IRPA. Enbridge Gas already offers interruptible rates to its Contract Rate customers (larger commercial, institutional and industrial customers). However, Enbridge noted that customers have been moving away from interruptible rates as they value certainty of supply over cost reduction.

No parties opposed the inclusion of demand-side IRPAs within the IRP Framework.

OEB staff submitted that demand-side IRPAs should receive a high priority in the IRP Framework, and that active deferral or avoidance of specific system needs is appropriate to address within the IRP Framework, not the post-2021 DSM Plan. OEB staff also submitted that storage (throughout Enbridge Gas's transmission and distribution system, or potentially on the customer side), although not explicitly mentioned in Enbridge Gas's list of potential IRPAs, should be considered as a solution to meet system needs.

Several parties (FRPO and OSEA) submitted that Enbridge Gas should consider enhancements to increase adoption of interruptible rates. In reply, Enbridge Gas indicated that it would investigate the drivers for recent declines in the use of interruptible services, and could potentially file revised interruptible and firm seasonal services/rates to make them more attractive to customers as part of its 2024 rebasing application.

Supply-side Gas IRPAs

Enbridge Gas also noted several supply-side natural gas solutions that could be considered as IRPAs and alternatives to pipeline construction. Injection of compressed natural gas into the pipeline system in a constrained area, or renewable natural gas sourced within the constrained area, could be potential alternatives to pipeline construction/expansion to meet a system need.

No parties objected to the consideration of the supply-side solutions proposed by Enbridge Gas. FRPO submitted that more consideration needed to be given to market-based supply-side alternatives and commercial transactions. FRPO submitted that through appropriate contractual arrangements requiring delivery of natural gas to specific points on Enbridge Gas's system, the capability of existing pipeline infrastructure (including non-Enbridge Gas pipelines including the TCPL mainline) could be harnessed to avoid or defer the need for Enbridge Gas to build new pipeline infrastructure.

Non-Gas IRPAs, including Electricity

Enbridge Gas sought approval to use non-gas alternatives, including electricity-based solutions, as IRPAs, and specifically requested confirmation from the OEB as to whether or not non-gas alternatives can be considered. Potential non-gas alternatives could include electric air source heat pumps, geothermal systems, and district energy systems. Enbridge Gas acknowledged that these would be new activities that go beyond gas distribution.

Enbridge Gas noted that it is permitted to undertake a broad range of activities within the utility corporation, where such activities are related to energy conservation, promotion of cleaner energy sources and ground source heat pumps, through its Undertakings to the Lieutenant Governor in Council, as supplemented by Orders in Council issued by the government of Ontario.

The ability for Enbridge Gas to undertake an activity does not necessarily mean that it is considered a rate-regulated activity, which is based on whether the activity is done as part of the sale of natural gas or the transmission, distribution and storage of gas, which requires an OEB order under s. 36 of the OEB Act. For example, in a decision regarding Enbridge Gas's application for a Renewable Natural Gas Enabling Program, the OEB determined that a proposed Renewable Natural Gas Upgrading service was a permitted activity for Enbridge Gas through its Undertakings, but would not be rate-regulated, as it was not done as part of the sale of gas or the transmission, distribution or storage of gas.[30]

Enbridge Gas submitted that, in the context of IRP, these non-gas activities would be directed at providing an alternative to distribution (or transmission or storage) facilities, and should be considered a rate-regulated activity, similar to the infrastructure being delayed or avoided.

Parties differed as to whether Enbridge Gas should be allowed to pursue non-gas activities. Parties such as ED, GEC, LPMA, and Pollution Probe supported broad consideration of IRPAs. ED and GEC specifically supported electric heat pumps, and ED and OEB staff noted that there was some precedent for Enbridge Gas considering fuel switching measures in the context of demand-side management activities in previous DSM Frameworks.

Parties expressing concerns around an expanded scope of IRPAs including non-gas activities (CME, IGUA, OEB staff, OGVG) generally argued that these activities may fall outside of the OEB's authority to set rates for the sale of gas or the transmission, distribution, and storage of gas under section 36 of the OEB Act. These activities could potentially involve disconnecting existing natural gas customers or avoiding the connection of new natural gas customers. Parties argued that this is not the proper role for a regulated gas distributor, and natural gas customers should not pay the costs to connect customers to electricity. OEB staff submitted that some applications of non-gas IRPAs may fall within the definition of section 36, but that this would likely be limited, and should not encompass providing energy services such as electricity to new customers who would not be connecting to Enbridge Gas's natural gas network.

In reply, Enbridge Gas indicated that if it is not permitted to offer non-gas IRPAs to customers who are not gas distribution customers, then this would greatly limit the ability of IRP efforts to respond to system expansion needs, which, by their nature, involve the connection of new customers. If Enbridge Gas is not able to offer non-gas IRPAs to such customers, Enbridge Gas submitted that it is very likely that IRP will not be a feasible alternative to meet the system expansion need.

[30] Decision and Order, Application for the Renewable Natural Gas Enabling Program (EB-2017-0319), October 18, 2018, pp. 10-11

GEC and OGVG suggested that, if the OEB determines that it is not appropriate for Enbridge Gas to offer electricity IRPAs, Enbridge Gas should still be required to include non-gas IRPAs in its assessment of alternatives, and, if the electric alternative is determined to be preferable, Enbridge Gas should be required to work with electricity sector entities (e.g. distributors) to facilitate the IRPA. Enbridge Gas submitted that this went beyond the scope of the proceeding, and is not feasible.

OEB staff indicated that the question of whether an alternative energy solution from a provider other than Enbridge Gas, such as an electricity distributor, was preferable could be addressed indirectly, at least for system expansion projects. This would be done by ensuring that any proposed Enbridge Gas system expansion projects were required to pass the E.B.O. 134/188 economic tests (discussed in section 8.3 ("Two-Stage Evaluation Process")), including whether the preferred approach is for Enbridge Gas to take no action. With these tests, system reinforcement costs are accounted for and may result in the requirement for customer contributions. OEB staff suggested that in areas with high system reinforcement costs, these provisions may lead potential customers to choose a different energy supply technology instead of connecting to the natural gas distribution network.

Role of Market Providers in Delivering IRPAs

Parties raised concerns about unfair competition with non-regulated providers, particularly if Enbridge Gas was allowed to offer electricity IRPAs such as geothermal or air source heat pumps, and if it was determined that Enbridge Gas would be allowed to capitalize some costs, and receive a regulated rate of return with an associated revenue requirement. This matter is discussed in chapter 12 (" IRPA Cost Recovery and Accounting Treatment Principles").

Enbridge Gas indicated that, in cases where a demand-side IRPA or an electricity IRPA involves equipment or activities already provided by the competitive market, it would look to this market to assist in providing solutions. For supply-side solutions, Enbridge Gas indicated that its role would depend on the nature of the supply-side solution, but that market-based solutions would be considered.

Short-Term IRPAs

Several parties including FRPO encouraged Enbridge Gas to consider shorter-term solutions to temporarily address a system constraint. Enbridge Gas acknowledged that a "bridging solution" to meet the need on a short-to-medium-term basis might be appropriate. However, Enbridge Gas stressed that a more permanent solution would be needed for the longer term.

Menu/Listing of IRPAs

Several parties, including Energy Probe, FRPO, and OEB staff, indicated that a listing or menu of IRPAs being considered by Enbridge Gas would be useful.

OEB staff suggested that Enbridge Gas should be required to develop and maintain a document on the best available information on IRPAs, filed with Enbridge Gas's annual IRP report. OEB staff suggested that the information provided could include the types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas's system, and learnings from pilot projects and other jurisdictions. OEB staff submitted that this would assist Enbridge Gas and other parties as a starting point for consideration of IRPAs for specific system needs and assist the OEB in its review of Enbridge Gas's consideration of alternatives in Leave to Construct/IRP Plan applications. Enbridge Gas agreed that a proposed record of information on available demand-side IRPAs would be a useful addition to the annual IRP Report; however, Enbridge Gas suggested that supply-side options were too situation-specific to include in the report.

Findings

Enbridge Gas is seeking OEB approval to use a wide variety of demand-side and supply-side IRPAs to meet identified needs/constraints.

Enbridge Gas has considerable experience with implementing demand-side solutions such as energy efficiency programs as part of its DSM Plans; however, the programs and measures in DSM Plans have been focused on reducing overall franchise-wide natural gas use for customers and increasing energy efficiency, rather than directed to targeted peak demand reduction to address system needs.

The OEB agrees that demand-side programming, including geotargeted energy efficiency, and demand response programs, should be part of the IRP Framework. The demand-side IRPAs are expected to target specific constrained areas and (among other objectives) encourage customers to reduce peak consumption. In regard to the December 1, 2020 letter and the relationship between the IRP Framework and DSM Plans, the OEB finds that potential merging of DSM energy efficiency with programs aimed at reducing peak demand to meet system needs is premature. Historically, the programs and measures in DSM Plans have been focused on reducing overall franchise-wide natural gas use for customers and increasing energy efficiency, rather than directed to targeted peak demand reduction to address system needs. The approved IRP Framework will provide opportunities to gain experience on demand-side programming that focuses on reducing peak demand. This experience is needed prior to any effort to merge DSM and IRP programming.

Regarding interruptible rates, ongoing rate design and customer adoption of current rates is part of normal operating process and should not need to be incented through an IRP Plan for Enbridge Gas to make enhancements. The OEB directs Enbridge Gas to study its interruptible rates to determine how they might be modified to increase customer adoption of this alternative service. This initiative is expected to help reduce peak demand, and the study should be filed as part of the next rate rebasing application. While approval of interruptible rates would be considered in a rebasing rate application, the impact of interruptible rates to meet a system need/constraint should be considered in an IRP Plan in combination with demand-side or supply-side alternatives.

Supply-side IRPAs, including market-based supply side alternatives, should also be considered, as should natural gas storage.

The OEB finds all of the above options appropriate to the extent that they are cost-effective, and risk has been evaluated and appropriately mitigated. For both demand side and supply-side IRPAs, the OEB supports Enbridge Gas procuring equipment or activities through the competitive market, where feasible and cost-effective. The OEB has concluded that Enbridge Gas should consider both combination IRP Plans (that may include multiple supply-side or demand-side IRPAs or an IRPA in combination with a Facility Alternative) and bridging solutions in its IRP Assessment Process if the bridging solution provides the best alternative in the near term, while exploring longer term solutions.

Enbridge Gas also proposed non-gas IRPAs, specifically electricity-based alternatives. The OEB has concluded that as part of this first-generation IRP Framework, it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs. This may be an element of IRP that will evolve as energy planning evolves, and as experience is gained with the IRP Framework.

Enbridge Gas can also seek opportunities to work with the IESO or local electricity distributors to facilitate electricity-based energy solutions to address a system need/constraint, as an alternative to IRPAs or facility projects undertaken by Enbridge Gas. However, the OEB is not establishing this as a requirement for Enbridge Gas. While in the longer term, there may be an opportunity to have integrated energy resource planning with the optimal fuel choice between all energy sources, the OEB concludes that this would be an excessively challenging requirement during this first-generation IRP Framework. As discussed in chapter 5 (“IRP Framework and Definition of IRP”), directing integrated energy planning between gas and electricity is premature and remains an aspirational goal. Within the Ontario government’s review of the long-term energy planning framework, approaches to selecting optimal energy choices may be assessed.

The guidance on IRPAs in the IRP Framework is based on broad categories of alternatives. The OEB concludes that a document on best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report. The OEB agrees with Enbridge Gas that supply-side alternatives require case-by-case examination and therefore are not required to be included in the listing.

8 IRP ASSESSMENT PROCESS

Enbridge Gas requested approval of a prescribed process, consisting of the four steps described below, to determine whether to pursue IRPAs for an identified need/ constraint.

1. Identification of Constraints

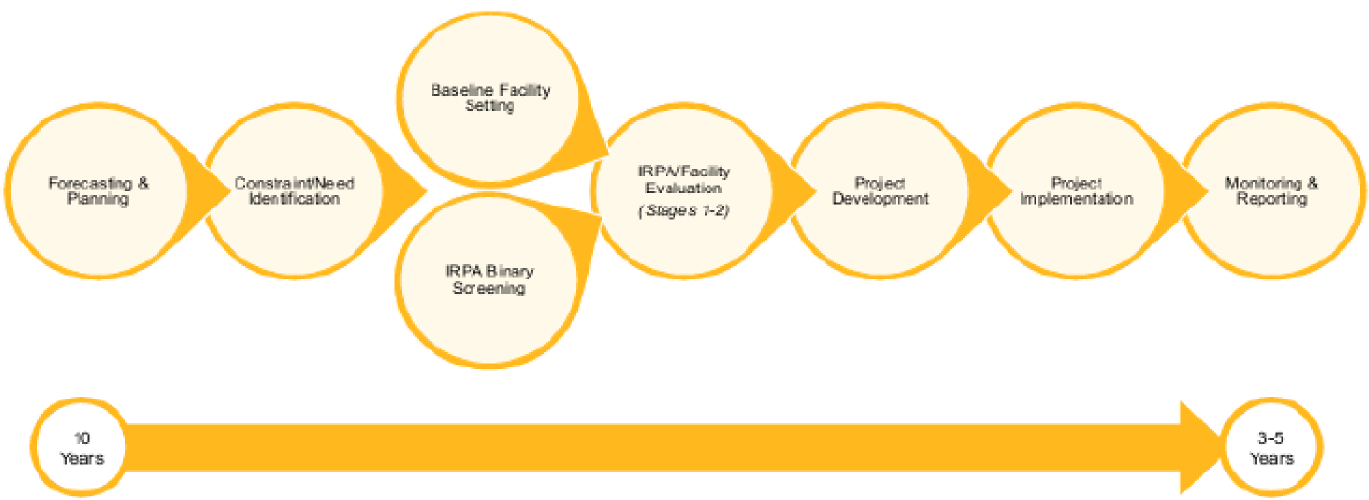
2. Binary Screening Criteria

3. Two-Stage Evaluation Process

4. Periodic Review

Enbridge Gas provided an illustrative process plan describing how it would incorporate its IRP proposal into its existing planning processes, as shown in Figure 1 below.[31]

Figure 1 – Enbridge Gas proposed IRP process



[31] Argument-in-Chief, p. 17

Review of Enbridge Gas's IRP Assessment Determinations

Enbridge Gas indicated that it would use the four-step IRP Assessment Process to determine the best approach to meeting system needs. Enbridge Gas proposed that the OEB would not explicitly oversee or approve Enbridge Gas's determinations in the IRP Assessment Process, until Enbridge Gas brought forward either an application for approval of an IRP Plan or a Leave to Construct application for approval of a facility project.

Several parties agreed with this approach. However, many parties submitted that there should be an opportunity for the OEB and stakeholders to review Enbridge Gas's decisions to not pursue IRP solutions for an identified need/constraint, as a result of its IRP Assessment Process, prior to a project-specific application.

Findings

The OEB is not requiring Enbridge Gas to seek approval for its determinations in the IRP Assessment Process prior to project-specific applications (for an IRP Plan approval or a Leave to Construct approval). In a project-specific application (Leave to Construct or IRP Plan), Enbridge Gas is required to demonstrate that it has followed the IRP Assessment Process, including the results of the analysis at each stage of the process.

However, the OEB is sympathetic to the concerns raised by parties, and has determined the most efficient approach to address this request is to use the annual IRP reporting proposed by Enbridge Gas, discussed in chapter 14 ("Monitoring and Reporting"). Within its annual IRP report, Enbridge Gas is to report on the results of its IRP Assessment Process, including reporting on those system needs where a negative result at step two (binary screening) or step 3 (technical/economic evaluation) resulted in a determination by Enbridge Gas for no further assessment of IRPAs. The IRP Technical Working Group will also be expected to review a draft of Enbridge Gas's annual IRP report, with the review coordinated by OEB staff. Material concerns that remain unresolved within the Technical Working Group will be brought to the attention of the OEB. This process is described in greater detail in chapter 10 ("Stakeholder Outreach and Engagement Process"). The risk that this approach will result in the OEB having no option but to approve a less than optimal project, and who should bear the consequences of this risk, is discussed in chapter 9 ("Allocation of IRP Risks").

8.1 IRP Assessment Process Step 1: Identification of Constraints

Enbridge Gas proposed that its asset management process would identify potential system needs/constraints up to ten years in the future, and describe these in annual updates to the Asset Management Plan (AMP). The AMP is currently filed each year as part of Enbridge Gas's rate adjustment proceedings. The AMP process addresses all utility assets within Enbridge Gas's regulated operations.[32] Under Enbridge Gas's proposal, IRP (and the consideration of IRPAs) would not be triggered by gas supply planning needs. [33]

Enbridge Gas indicated that this ten-year horizon would permit time to consider whether an IRP Plan could meet the identified system needs and, if so, to develop, evaluate and implement an IRP Plan in time to determine whether it is likely to meet the need or constraint.

Enbridge Gas indicated that the consideration of the potential role of IRP Plans for meeting each system need identified during this step, and the current status of IRP Plan consideration, would be documented in Enbridge Gas's AMP. An updated version of this information would be provided each year.[34] Enbridge Gas proposed that the first version of the AMP reflecting this updated process would be filed in Fall 2022.

Parties were generally supportive of Enbridge Gas's proposed approach to identifying system needs/constraints and documenting the current status of consideration of IRP Plans to meet these needs within the AMP on an annual basis. Regarding the scoping of needs identification for the purposes of IRP, OEB staff supported the scoping of IRP to address infrastructure needs, not gas supply planning needs.

OEB staff proposed that the information filed within each AMP should include a list of identified system needs, and for each system need, the status of IRP Plan consideration in regards to meeting the need. This should include the result of the initial binary screening (section 8.2, "Binary Screening Criteria"), and details as to whether and why IRP Plans had been screened out at subsequent steps, with supporting rationale. Enbridge Gas accepted this suggestion.

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[32] AMP 2021-2025, section 1.1
[33] Exhibit I. Staff.2
[34] Enbridge Gas's 2021-2025 Asset Management Plan covered a five-year period, but Enbridge Gas has indicated that it will increase the scope of future AMPs back to 10 years, in support of longer-term planning initiatives such as IRP. Exhibit I.Staff.6a

Demand Forecast

Enbridge Gas's demand forecast is a critical input to the AMP and the needs identification process. Peak period demand, and growth in peak period demand, is the main driver of the system needs that are identified in Enbridge Gas's AMP, at least for the types of needs where IRP Plans are likely to be considered.[35]

These system needs are identified based on Enbridge Gas's demand forecast, and in particular, its design day demand forecast, which forecasts Enbridge Gas's requirements in order to meet customer needs on the day of the year with highest demand.

Forecasting design day demand involves many variables, including weather projections, modeling of the annual consumption and temporal demand profile of Enbridge Gas customers, and assumptions regarding any projected increase (or decrease) in the number of Enbridge Gas customers.[36]

Enbridge Gas did not propose any changes to its existing demand forecasting methodology in this proceeding.

Many parties raised concerns with Enbridge Gas's demand forecasting methodology and assumptions; in particular, whether the assumptions in Enbridge Gas's forecast regarding future natural gas demand were consistent with public policy objectives and actions to transition to a lower-carbon energy future. This energy transition is likely to involve reducing greenhouse gas emissions from the energy sector through a combination of lower-carbon energy sources (which could include lower-carbon sources of natural gas or other gaseous fuels such as hydrogen, and alternative energy sources such as electrification) and reduction in energy demand through efficiency and conservation. The role Enbridge Gas will play in this transition, as well as the speed at which this transition will occur, are uncertain.

Parties noted that, if natural gas demand from customers is lower than forecast due to this energy transition, then projected system needs (whether they are to be met by a facility project or an IRP Plan) may not materialize, introducing a risk of stranded or underutilized assets.

[35] Exhibit I.Staff.5(a)
[36] See Enbridge Gas's 5 Year Gas Supply Plan and Exhibit I.4.Staff(a) for more details on Enbridge Gas's demand forecasting methodology.

Environmental Defence and GEC submitted that Enbridge Gas should be directed to consider the potential impacts of decarbonization on gas demand through scenario or sensitivity analysis, and Environmental Defence stated that Enbridge Gas's planning implicitly assumes a 0% probability of declining gas demand. SEC recommended that the OEB require Enbridge Gas to consider stranded asset risk associated with possible declining natural gas demand in its AMP that will be filed in its next rebasing application, primarily through scenario analysis. GEC also submitted that the IRP Framework should require regular assessment of the accuracy of demand forecasts.

Anwaatin recommended that Enbridge Gas take account of the broader policy and regulatory context around greenhouse gas emissions reductions in developing its demand forecast, including the federal government's intent to implement a price on greenhouse gas emissions that will continue to rise to $170/tonne CO_2e by 2030, instead of assuming that the price will remain at $50/tonne CO_2e after 2022. This proposed emissions pricing increase has been announced, but not yet implemented in law, by the Government of Canada.[37] The issue of carbon pricing is also pertinent to cost-effectiveness analysis, discussed in section 8.3 ("Two-Stage Evaluation Process").

In addition to the concerns raised about incorporating decarbonization considerations into demand forecasts, the EFG report filed by GEC/ED suggested that Enbridge Gas's forecast and design day demand inputs may be overly conservative.[38]

OEB staff submitted that the details of the demand forecast methodology do not need to be addressed in the IRP Framework, but did submit that the IRP Framework should require Enbridge Gas to file the supporting ten-year demand forecast that underpins its identification of system constraints, as part of its annual AMP updates. OEB staff also suggested that questions on the demand forecasting methodology could potentially be considered at rebasing, including whether Enbridge Gas's demand forecast is compatible with the existing guidance in the Filing Requirements for Natural Gas Rate Applications.[39]

Enbridge Gas agreed with OEB staff that the demand forecasting methodology could be considered at rebasing, and did not support any of the suggestions from other parties for mandatory changes to the demand forecasting approach as part of the IRP Framework.

[37] Government of Canada, "A Healthy Environment and a Healthy Economy", p. 26
[38] EFG Report (Exhibit M2.GEC-ED), pp. 35-36
[39] Ontario Energy Board, *Filing Requirement for Natural Gas Rate Applications*, February 16, 2017.

Findings

For this first-generation IRP Framework, the OEB finds the process proposed by Enbridge Gas to identify system constraints or needs is acceptable. Recording potential system needs/constraints up to ten years in the future in the AMP will allow time for a detailed examination of IRPAs. The OEB agrees with Enbridge Gas's proposal that the first version of the AMP reflecting this updated process be filed in Fall 2022.

The OEB directs that the AMP include information about Enbridge Gas's system needs. This includes providing the status of consideration of IRP Plans in regard to meeting system needs, the result of the binary screening, and details on the evaluation. The AMP should also identify any material changes to the demand forecast, relative to the demand forecast that was assessed as part of the most recent rebasing application. As discussed in chapter 14 ("Monitoring and Reporting"), Enbridge Gas will be expected to include relevant information from the AMP, including the most recent results of its IRP Assessment Process for system needs, within its annual IRP report.

The OEB expects that for projects brought to the OEB for approval (both Leave to Construct projects and IRP Plans), the system need will have previously been identified in the AMP (although the preferred project to meet the system need may not have been determined at that time). For any previously unidentified needs, Enbridge Gas will need to provide an explanation as to why the project is needed at this time.

Despite concern raised by some parties about the demand forecast, the OEB has determined that a more comprehensive review of Enbridge Gas's demand forecasting methodology is not needed at this time. Detailed examination of the ten-year demand forecast methodology is appropriately done at Enbridge Gas's next rebasing application, at which time the AMP will be filed as evidence. The OEB also notes that an analysis of the historical accuracy of Enbridge Gas's demand forecast is required by section 2.3.2 of the Filing Requirements for Natural Gas Rate Applications, and thus it is appropriate to file this information at its next rebasing application.

8.2 IRP Assessment Process Step 2: Binary Screening Criteria

Enbridge Gas proposed to apply five binary screening criteria to system needs/constraints identified in the AMP to determine whether further IRP evaluation is appropriate. Enbridge Gas submitted that it is necessary to establish the appropriate scope and scale of system constraints/needs that should qualify for IRP assessment, and that undertaking the full IRP planning process for every forecasted system constraint/need would be a substantial incremental administrative cost burden. Suitable screening criteria would allow IRP efforts to be focused on appropriate projects with the highest likelihood of success. Enbridge Gas also noted that expert evidence filed in this proceeding showed that binary screening is performed in other jurisdictions undertaking gas and electric IRP.

Enbridge Gas indicated that facility expansion/reinforcement projects, where growth is the main driver, will be the area where IRP will be most effectively applied. Enbridge Gas defines facility expansion/reinforcement projects as projects designed to meet system needs arising from the addition of new customers to the system or from the increasing load/demands of existing customers, and are projects that support the transmission and distribution of natural gas at the system level as opposed to projects that are required to connect a specific customer.[40] However, Enbridge Gas indicated that IRP should also be considered for larger pipeline replacement and relocation projects, as there may be opportunities to reduce the size of the replacement.[41]

System needs where IRP is not screened out through this binary screening would next move to the two-stage IRP evaluation process, described in section 8.3, “Two-Stage Evaluation Process”.

Most parties accepted or agreed with the general intent to use screening criteria. CME and OEB staff noted that Enbridge Gas should use judgement in applying the criteria, if there are cases where it believes that further IRP consideration may be appropriate, even if the system need did not strictly pass the screening criteria.

Specific screening criteria

Enbridge Gas indicated that, after excluding system needs in the AMP that do not pertain to gas-carrying assets (buildings, fleet, IT, etc.), it would apply five binary screening criteria to identified system needs/constraints to determine whether further IRP evaluation is appropriate. Binary screening would exclude a system need from further IRP consideration.

These criteria were modified by Enbridge Gas throughout the proceeding. The final binary criteria proposed by Enbridge Gas, along with additional considerations, are described below.[42]

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40 Exhibit I.Staff.7
41 Exhibit JT 2.11
42 Exhibit J1.4

Emergent safety issues: *If an identified system constraint/need is determined to require a facility project in order for Enbridge Gas to ensure its continued ability to offer safe and reliable service or to meet an applicable law, it would not be a candidate for IRP analysis. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and needed to be replaced as quickly as possible to ensure the safety of local communities and the Company's broader transmission and distribution systems. Enbridge Gas has acknowledged that longer-term safety related system constraints/needs may be appropriate for an IRPA solution and would be considered on a case-by-case basis.*

Enbridge Gas's proposed wording for this criterion evolved during the proceeding, in response to concerns from parties that many or most system needs could be classified as safety issues, and hence, screened out from further IRP consideration. Enbridge Gas's final proposed wording clarified that only system needs that were emergent safety issues would be excluded from IRP consideration using this criterion. Some parties submitted that, even with these revisions, the proposed wording was too broad or subjective.

Timing: *If an identified system constraint/need must be met in under 3 years, an IRPA cannot be implemented and its ability to resolve the identified system constraint/need cannot be verified in time. Therefore, an IRP analysis is not prudent. Exceptions to this criterion, could include: (i) Supply-side solutions like CNG; (ii) Bridging or market-based alternatives in combination with other IRPAs, where such exceptions/IRPAs can address a more imminent constraint/need.*

Enbridge Gas indicated that it expects most system needs to be identified more than three years in advance through its long-range planning process.[43] However, it noted that, at the outset of the IRP Framework, this will not be the case, as there will be a certain number of near-term needs that are known, but which have not yet been subject to the IRP Framework.

Customer-specific builds: *If an identified system constraint/need has been underpinned by a specific customer's (or group of customers') clear determination for a facility option and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities (including new*

[43] Exhibit I.Staff.8d

subdivision or small main extensions) then it is not appropriate to conduct IRP analysis for those projects.

Some parties submitted that this criterion may not guarantee that a specific customer's preference for a facility project over an IRPA will not impose costs on other Enbridge Gas customers, and that if other customers do incur costs, Enbridge Gas should be required to consider IRPAs.

Environmental Defence specifically recommended that new subdivisions and small main extensions should not be excluded from further IRP consideration, as they are highly cost-effective opportunities for IRPAs.

CME and OEB staff submitted that Enbridge Gas should play a role in informing customers of potential IRPAs that might reduce their Contribution in Aid of Construction (by reducing the size and cost of the facility project).

Community expansion: *If a facility project has been driven by policy and related funding to explicitly deliver natural gas into communities to help bring heating costs down, then it is not appropriate to conduct an IRP analysis. Where Government grants are not identified for the specific purpose of growing natural gas access, then IRP could be considered for community expansion provided IRPAs such as district energy systems were included in scope.*

Enbridge Gas clarified that this was limited to specific projects named in O. Reg. 24/19 (Expansion of Natural Gas Distribution Systems).[44] O. Reg. 24/19 was made under the OEB Act (as amended by the *Access to Natural Gas Act*),[45] and supports the Government of Ontario's Natural Gas Expansion Program, which is intended to help expand access to natural gas to areas of Ontario that currently do not have access to the natural gas distribution system. O. Reg. 24/19 lists specific projects as being eligible for a maximum amount of rate reduction, which is collected from all gas customers, to fund a portion of the system expansion costs. On June 9, 2021, the Government of Ontario announced an additional 28 projects were selected for funding in the second phase of the Natural Gas Expansion Program, and O. Reg. 24/19 was amended to add these projects.[46]

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[44] Exhibit I.Staff.8f
[45] *Access to Natural Gas Act, 2018*, S.O. 2018, c. 15 - Bill 32
[46] Government of Ontario, "Ontario Expands Access to Natural Gas in Rural, Northern and Indigenous Communities", June 9, 2021.

Several parties submitted that the availability of project funding under O. Reg. 24/19 should not prevent Enbridge Gas from considering IRPAs. GEC and SEC encouraged consideration of lower-cost non-gas alternatives (which could potentially be delivered by parties other than Enbridge Gas) that would completely eliminate the need for a natural gas connection, while Anwaatin and LPMA noted the possibility of an IRPA that would reduce the size and cost of the facility project to connect these communities.

Pipeline replacement and relocation projects: *If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than $10 million, then that project is not a candidate for IRP analysis. Enbridge Gas acknowledges that for large pipeline replacement and relocation projects, there may be opportunities to reduce their size through consideration of IRPAs in the future. Accordingly, the Company would investigate such opportunities in the future on a case-by-case basis, taking into account the broader impacts of downsizing (e.g. creation of system bottlenecks or integrity and inspection concerns). The Company does not believe that IRP will be appropriate for smaller scale pipeline replacement projects (less than $10 million cost), as the cost savings that would result from downsizing pipeline size will not be significant enough to support consideration of IRPAs.*

Originally, Enbridge Gas proposed to screen out all replacement and relocation projects from further IRP analysis, but this proposal evolved over the course of the hearing. The $10 million threshold proposed by Enbridge Gas aligns with the proposed change to O. Reg. 328/03 under the *Ontario Energy Board Act, 1998*, that, if implemented, would raise the cost threshold as to which pipeline projects require Leave to Construct approval from $2 million to $10 million.[47]

Some parties expressed concerns that a $10 million threshold may be too high and would screen out a large number of system needs from further IRP evaluation.

GEC submitted that this criterion should not be used to screen out replacement and relocation projects where pipeline size or capacity is being increased. Enbridge Gas agreed with this proposal.

[47] Environmental Registry proposal 019-3041. On July 16, 2021, a second proposal (Environmental Registry proposal 019-4029) was posted, seeking comments on the specific proposed regulatory amendments.

Findings

The OEB concludes that the establishment of screening criteria to select which system needs require IRP assessment is appropriate.

The OEB agrees that there must be a focus on those situations where there is a reasonable expectation that an IRPA could efficiently and economically meet the system need. The OEB notes that other jurisdictions have used initial screening for IRP suitability including criteria such as minimum lead time required and minimum project costs.

The OEB has determined that the following criteria will be appropriate for the first-generation IRP Framework. With more experience, there may be an opportunity to modify these criteria in the future.

<u>Emergent Safety Issues</u>

The first criterion deals with urgent or imminent issues. The OEB agrees with Enbridge Gas that the safety and reliability of the gas system is paramount. Removing constraints that jeopardize this system performance does not allow time for the development and assessment of an IRP Plan.

i. **Emergent Safety Issues** – *If an identified system constraint/need is determined to require a facility project for Enbridge Gas to offer safe and reliable service or to meet an applicable law, an IRP evaluation is not required. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and needed to be replaced as quickly as possible to ensure the safety of local communities and Enbridge Gas's broader transmission and distribution systems. Longer-term safety related system constraints/needs may be appropriate for an IRP Plan and should be considered on a case-by-case basis.*

<u>Timing</u>

It takes time to assess and implement an IRP Plan along with demonstration that the constraint is being mitigated. Once a ten-year AMP consistent with the IRP Framework has been in place for several years, there should be fewer situations where a timing criterion is needed; however, for this first-generation IRP Framework, the OEB is establishing a timing criterion. The OEB notes that the use of supply-side options might be possible to meet an identified need within a shorter period.

ii. ***Timing*** *– If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.*

Customer-Specific Builds

Where the customer fully pays for the incremental infrastructure costs associated with a facility project, in the form of a Contribution in Aid of Construction, the OEB finds that consideration of an IRP Plan will not be required.[48] However, the OEB encourages Enbridge Gas to discuss DSM opportunities with customers to potentially reduce the size of the build.

iii. ***Customer-Specific Builds*** *– If an identified system need has been underpinned by a specific customer's (or group of customers') clear request for a facility project and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required.*

Community Expansion & Economic Development

Given the goal of the Ontario Government's Access to Natural Gas legislation[49] to extend gas service to designated communities, the OEB will not require Enbridge Gas to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need. However, the OEB encourages Enbridge Gas to discuss DSM opportunities with customers to potentially reduce the size of the build.

iv. ***Community Expansion & Economic Development*** *– If a facility project has been driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities, then an IRP evaluation is not required.*

[48] The incremental costs recovered through a Contribution in Aid of Construction are set at an amount that reduces the capital cost of a project for Enbridge Gas ratepayers such that the project becomes economically feasible, which generally requires a profitability index greater than or equal to one.
[49] *Access to Natural Gas Act, 2018*, S.O. 2018, c. 15 - Bill 32

Pipeline Replacement and Relocation Projects

The OEB has determined that a minimum cost of the facility project is required to justify the time and effort to conduct an IRP evaluation and potentially develop an IRP Plan. The OEB finds that projects under $2 million should be screened out unless the government makes regulatory changes establishing a $10 million threshold for OEB Leave to Construct approvals, in which case, the criteria should use $10 million to determine if an IRP evaluation is appropriate.

v. ***Pipeline Replacement and Relocation Projects** – If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than the minimum project cost that would necessitate a Leave to Construct approval, then an IRP evaluation is not required.*

8.3 IRP Assessment Process Step 3: Two-Stage Evaluation Process

For system needs progressing past the initial IRP binary screening, Enbridge Gas proposed determining whether to proceed with an IRP Plan through a two-stage evaluation.[50] First, Enbridge Gas would determine whether potential IRPAs could meet the identified constraint/need. If yes, then Enbridge Gas would compare one or more IRP Plans to the baseline Facility Alternative, using a Discounted Cash Flow-plus (DCF+) economic test, to determine the optimum solution to meet the system need.

Enbridge Gas indicated that the two-stage evaluation process would commence sufficiently far in advance of the date that the constraint/need must be met in order to allow for time for an IRP Plan to be developed, approved, implemented and monitored for effectiveness in advance of the date when a facility project would be required.

Stage 1: Technical Evaluation

The first stage would look at the technical viability of potential IRPAs to reduce peak demand to the degree required to meet the identified system need, using best available information to determine whether an IRP Plan including one or more IRPAs would be a viable option. Enbridge Gas noted that to address the lack of experience with IRPAs and the associated risk of under delivery of peak period savings, it may need to employ a derating factor (i.e., assuming less than 100% of the forecast peak demand reduction

[50] Argument-in-Chief, pp. 27-31

from the IRPAs would be delivered). This would lead to Enbridge Gas oversubscribing the amount of IRPAs, in order to have adequate assurance of expected results.

Parties had few comments on the first stage of the evaluation process and were generally supportive. Enbridge Gas confirmed that it will consider all feasible and available IRPAs when conducting the stage one technical evaluation, and indicated that its information on best available information on IRPAs included with its annual IRP report would aid with this consideration.

Several parties commented on Enbridge Gas's intent to use derating factors and questioned the need for oversubscription to IRPAs, or submitted that treating this aspect of risk related to IRPAs but not addressing other economic risks associated with facility projects was one-sided. GEC submitted that as experience is gained with IRPAs, the derating factor should be adjusted to more accurately reflect the risk. OEB staff submitted that the reliability and economic risks associated with both IRPAs and Facility Alternatives should be quantified within the subsequent economic evaluation, to the degree possible.

Stage 2: Economic Evaluation

Enbridge Gas proposed that the economic evaluation would consist of a three-phase DCF+ evaluation to compare the IRP Plan(s) to the baseline Facility Alternative. This test would be based on the three-phase economic test that Enbridge Gas is required to use to assess the costs and benefits of potential transmission system expansions, under the parameters established by the *Report of the Board on the Expansion of the Natural Gas System in Ontario* (the E.B.O. 134 report). The principles of this test are summarized in the OEB's *Filing Guidelines on the Economic Tests for Transmission Pipeline Applications*.[51]

In the context of IRP, Enbridge Gas calls this a DCF+ test.

- Phase 1 assesses the economic benefits and costs from the utility perspective, and indicates whether the project is likely to result in future increases to utility rates.

[51] A recent example of how this three-phase test (including the concept of summing the results of the three phases) has been used for transmission system expansions can be seen for the proposed Dawn-Parkway expansion project (EB-2019-0159): Application and Evidence, Exhibit A, Tab 8. Enbridge Gas has also provided a hypothetical example of how this test could work in comparing facility projects and IRPAs in Exhibit JT 2.15.

- Phase 2 assesses the incremental economic benefits and costs incurred by customers from the IRP Plan(s) or Facility Alternative(s).
- Phase 3 assesses the incremental societal benefits and costs.

The categories of benefits and costs that Enbridge Gas proposes to include in each phase are shown in Table 2.[52]

Table 2: Discounted Cash Flow-Plus Test Costs and Benefits

Benefit/Cost	Phase 1	Phase 2	Phase 3
Benefits			
Incremental Revenues	x		
Avoided Utility Infrastructure Costs [2]	x		
Avoided Customer Infrastructure Costs [3]		x	
Avoided Utility Commodity/Fuel Costs [4]	x		
Avoided Customer Commodity/Fuel Costs [5]		x	
Avoided Operations & Maintenance	x		
Avoided Greenhouse Gas Emissions		x	
Other External Non-Energy Benefits			x
Costs			
Incremental Capital Expenditure [1]	x		
Incremental Operations & Maintenance [1]	x		
Incremental Taxes	x		
Incremental Utility Commodity/Fuel Costs [4]	x		
Incremental Customer Commodity/Fuel Costs [5]		x	
Incremental Greenhouse Gas Emissions		x	
Incremental Customer Costs		x	
Other External Non-Energy Costs			x

Notes:
(1) Capital and Operations & Maintenance is inclusive of program administrative costs
(2) Avoided or reduced infrastructure capital costs of the utility (e.g., smaller diameter pipe)
(3) Avoided or reduced infrastructure capital costs of the customer (e.g., reduced Contribution in Aid of Construction)
(4) Avoided or incremental fuel costs of the utility (e.g., compressor fuel and unaccounted for gas)
(5) Avoided or incremental fuel costs of the customer (e.g., lower/higher natural gas use, lower/higher electricity use)

[52] Exhibit JT 2.2

A net present value would be calculated for each phase. Results from each phase would be presented separately for transparency, but would also be summed together.

The DCF+ results for the IRP Plan(s) and the baseline Facility Alternative would be compared to one another, to determine which alternative is optimal. IRP Plans that included some combination of IRPA and facility project could also be tested using this approach.

While economics would be a factor in the final decision as to how best meet a system need, Enbridge Gas indicated that other considerations (safety, public policy, reliability) that are potentially difficult to quantify would also play a role in the final decision as to which IRPA or facility project is selected.

The primary alternative economic approach discussed in this hearing was a Total-Resource Cost-plus (TRC+) test. This is a single-phase test that is used in Ontario to assess the cost-effectiveness of DSM programs, by measuring the energy-related benefits and costs of DSM programs experienced by both the gas utility system and participants in DSM programs, as well as an adder that accounts for non-energy benefits associated with DSM programs.[53] Similar to the TRC+ test is the Societal Cost Test, which Con Edison has proposed to use as its cost-effectiveness test to evaluate IRP activities in New York State.[54] The Societal Cost Test is also a single-phase test that assesses all energy and non-energy related costs and benefits from a societal perspective.

Parties were split between the merits of a DCF+ test or TRC+ test.

Enbridge Gas expressed a preference for the three-phase DCF+ test, as opposed to an "all-in-one" test such as the TRC+ test, because the TRC+ test on its own does not provide any indication of the rate impact or potential for cross-subsidization of the IRP Plans and Facility Alternatives considered (information that is provided in phase 1 of the proposed DCF+ test). Enbridge Gas also noted that while the TRC+ test is used in Ontario to measure the cost-effectiveness of energy efficiency type programs, it has little or no experience using a TRC+ test to evaluate facility projects in the context of

[53] Ontario Energy Board, Demand Side Management Framework for Natural Gas Distributors (2015-2020), s.9
[54] Con Edison, Proposal For Use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution infrastructure, September 15, 2020, p. 24

meeting system needs, in contrast to Enbridge Gas's extensive experience using the DCF test.

Enbridge Gas's proposal indicated that the results of all three phases of the DCF+ test would be summed together, with the overall results used to determine which alternative is optimal.

The submissions of many of the other parties supporting the DCF+ test indicated that the first phase of the DCF+ test (which assesses the economic benefits and costs from the utility perspective, and identifies whether the project is likely to result in future increases to utility rates) should be given primacy in the economic evaluation. These parties submitted that the test selected needs to focus on solutions that meet the system constraint and that benefit all Enbridge Gas customers paying postage stamp transmission and distribution rates. They expressed the concern that the TRC+ test could require Enbridge Gas customers to pay more for an IRP Plan than they would otherwise have to pay for a pipeline solution that meets the same need. This is because an IRP Plan could score favourably on the TRC+ test, even if the benefits go primarily to customers participating in an IRPA (e.g., a geotargeted energy efficiency program) or to society as a whole, not to all Enbridge Gas customers. APPRO noted (in supporting a DCF+ approach) that phase 1 of the DCF+ test served a gating function, protecting Enbridge Gas customers from this outcome. Similarly, IGUA submitted that to the extent that an IRPA drives a higher cost than the baseline utility infrastructure which it is intended to avoid, it should not be approved, even if its overall societal benefit is calculated to be superior to that of the baseline utility solution.

Several parties argued that the TRC+ test is more appropriate, based on three main points. First, no other jurisdiction uses a test similar to the DCF+ test to compare facility and non-facility options (including demand-side options). Second, the TRC+ test is the best way to evaluate the overall cost-effectiveness of alternatives taking into account all relevant factors, including potential commodity cost savings to customers and greenhouse gas emissions reductions (which can be considered in phases 2 or 3 of the DCF+ test, but not in the first phase). Third, it is not logical to assess demand-side IRPAs using a different economic test than the OEB currently uses to evaluate Enbridge Gas's DSM activities under the DSM Framework.

Several parties also raised methodological concerns with Enbridge Gas's proposal to add the results of the three phases of the DCF+ test together.

Some parties supporting a TRC+ test indicated that it could be appropriate to include a secondary test (similar to the DCF+ phase 1) to assess ratepayer impact considerations of IRP Plans and Facility Alternatives.

Further Work on Economic Evaluation Methodology

All parties, whether supporting a DCF+ or TRC+ economic test, agreed that further work should be done regarding the specifics of using the preferred test for comparing IRPAs and Facility Alternatives. Guidehouse indicated in testimony that the existing tests leave a lot of gaps and uncertainties about how they would be applied to IRP. Enbridge Gas accepted Guidehouse's recommendation that parties work to complete a Benefit Cost Analysis Handbook or supplemental guide to E.B.O 134 to improve the comprehensiveness of the DCF+ test for economic evaluations, and that this would be an appropriate activity for the IRP Technical Working Group.

Some parties raised specific considerations regarding the treatment of costs and benefits. Several parties proposed that Enbridge Gas value avoided greenhouse gas emissions based on the assumption that this value will continue to rise over time, instead of assuming that the price will remain at \$50/tonne CO_2e after 2022, as is currently in law. This could include (but would not necessarily be limited to) the federal government's intent to implement a price on greenhouse gas emissions that will continue to rise to \$170/tonne CO_2e by 2030. Enbridge Gas indicated that it could accommodate adding a scenario to its DCF+ analysis that would include different carbon pricing assumptions, although it may not necessarily agree with other parties as to how the results of such an alternative scenario would be used in determining the preferred solution.

OEB staff and several other parties made additional suggestions for specific items that should be included in the economic test. OEB staff submitted that the economic test should include impacts on Enbridge Gas's gas supply costs and should also quantify reliability and economic risk if possible. Enbridge Gas submitted that it would take these suggestions into consideration, but including these types of details in the IRP Framework is a level of granularity that is not necessary or possible at this time.

Cross-Subsidization Concerns For Projects Benefiting New Customers

Several parties, whether favouring a TRC+ test or DCF+ test to compare IRPAs and Facility Alternatives, indicated that the existing E.B.O. 188 and E.B.O. 134 tests should continue to be required as economic tests to assess whether to proceed with system expansion projects to serve new customers. As noted above, the E.B.O. 134 test is a three-phase test used as an economic test for transmission system expansions, that Enbridge Gas has modeled its DCF+ test on. The E.B.O. 188 test[55] is used as an economic test for a proposed distribution system expansion and only includes the first phase of the DCF test.

OEB staff noted that Enbridge Gas's economic feasibility policies[56] supporting the E.B.O. 188 guidelines enable Enbridge Gas to require a customer contribution, in the form of a Contribution in Aid of Construction, System Expansion Surcharge, or Temporary Connection Surcharge, to address cross-subsidization concerns between new and existing customers. These customer contributions can improve the net present value and profitability index of a project under the E.B.O. 188 test (DCF phase 1). OEB staff submitted that this approach could also be used for IRPAs. OEB staff submitted that Enbridge Gas should review its economic feasibility policies to ensure that the system reinforcement costs used as inputs are based on a forward-looking approach that accounts for system needs/constraints identified in the AMP, and submit the revised policies in its rebasing application. Enbridge Gas indicated that it would consider including this update into its economic feasibility policies to be presented for approval at rebasing, but did not believe that this needed to be ordered by the OEB or included in the IRP Framework.

Findings

<u>Technical Evaluation</u>

The OEB concludes that it is appropriate for Enbridge Gas to undertake a technical evaluation to first determine if the IRPAs considered can meet the need, prior to doing an economic evaluation. The OEB accepts that Enbridge Gas may use derating factors or oversubscription of IRPAs to address uncertainty regarding forecast savings. These derating factors may be relevant to both the technical and economic evaluations. The OEB has also determined that Enbridge Gas should include in its request for OEB approval of specific IRP Plans both the level of oversubscription and the supporting rationale.

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[55] The E.B.O. 188 test is described in the OEB's Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario
[56] The most recent version of these policies can be found in EB-2020-0094, Exhibit C, Tab 2, Schedules 1 and 2 for the EGD and Union rate zones.

Economic Evaluation

The OEB concludes that the DCF+ test, including its focus on rate impacts (as identified in phase 1 of the DCF+ test), should be the economic evaluation test used in the IRP Framework. The OEB agrees that the test selected should be the one that best aligns with the goal and purpose of IRP planning, which is to address the system needs of Enbridge Gas's regulated operations and identify and implement the solution that is in the best interest of Enbridge Gas and its customers. The purposes of DSM and IRP are distinct from each other. The OEB has determined that the primary objective of Enbridge Gas's post-2021 DSM Plan should be to assist customers in making their homes and businesses more efficient in order to better manage their energy bills.[57] DSM is aimed at reducing annual natural gas usage, and IRP is aimed at reducing peak demand in specific geographic areas to replace infrastructure investment with an IRPA investment. Given the separate purpose, it is reasonable that a different economic test should be applied in the IRP Framework than in the DSM Framework. The OEB finds that an IRP Plan is attempting to reduce the longer-term cost to all Enbridge Gas customers, accordingly it is important to have an evaluation test that looks at impacts from the gas customer perspective. That is also consistent with the OEB's statutory objectives.

Where the two-stage evaluation process reveals that an IRP Plan is the best alternative to meet an identified need/constraint, then Enbridge Gas is encouraged to make application to the OEB for approval of the IRP Plan, and then implement and monitor the IRP Plan and make adjustments as appropriate. The OEB finds that Enbridge Gas should be given some discretion in selecting an alternative to meet a system need that does not have the highest score on phase 1 of the DCF+ test, as there may be considerations or factors that are important in phases 2 or 3, or are difficult to quantify. However, Enbridge Gas would require full justification of their proposal if they recommend a higher cost alternative.

Further Work on Economic Evaluation Methodology

The OEB accepts the categories of benefits and costs proposed by Enbridge Gas for the three phases of the DCF+ test (shown in Table 2) for the use of this test in the IRP Framework. The OEB recognizes that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRPAs, and clarify how these costs and benefits should be considered within the DCF+ test. This could

[57] OEB Letter, Re: Post-2020 Natural Gas Demand Side Management Framework, December 1, 2020

include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP. Enbridge Gas is encouraged to consult with the IRP Technical Working Group and to use the IRP pilot projects as a testing ground for an enhanced DCF+ test. In particular, the OEB considers it appropriate for the Technical Working Group to consider how different carbon pricing scenarios should be used in the DCF+ calculation. The OEB directs that Enbridge Gas file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.

Cross-Subsidization Concerns for Projects Benefiting New Customers

The E.B.O. 134 and 188 tests were designed to determine whether a natural gas distribution or transmission expansion project was compatible with the OEB's objective to facilitate rational expansion of transmission and distribution systems. The OEB concludes that the results of the DCF+ test that will be required in the IRP Framework will be of similar assistance in determining whether a proposed IRP Plan to serve new customers is compatible with this objective.

This emphasis on cost-effectiveness and avoiding cross subsidization between new customers and existing customers led to the consideration of customer contributions, in the form of a Contribution in Aid of Construction, System Expansion Surcharge, or Temporary Connection Surcharge for infrastructure projects. The OEB concludes that these same charges could be applied to an IRP Plan where the IRP Plan is being proposed for the benefit of new customers, to reduce cross-subsidization and improve the net present value and profitability index of an IRP Plan in part 1 of the DCF+ test.

8.4 IRP Assessment Process Step 4: Periodic Review

Enbridge Gas indicated that where circumstances change (for example, the nature or timing of an identified need/constraint alters materially, or significant policy changes are announced by government or the OEB), it would review its IRP determinations and report on the outcome of its re-evaluation within the AMP and/or annual reporting. Under changes with system-wide implications and importance, Enbridge Gas suggested that a discussion with the IRP Technical Working Group might occur to review the change.

Several parties submitted that Enbridge Gas should inform the OEB and stakeholders at the time such changes were identified, with the potential for further review. Enbridge Gas opposed this suggestion, and indicated that, in its initial IRP evaluation process, it would be reporting on and engaging with stakeholders on a periodic basis at a higher level, not on a project-by-project basis, and that the same approach was appropriate when circumstances change and decisions are revisited.

Enbridge Gas also clarified that, in regard to modifications to approved IRP Plans, it proposed to seek approval from the OEB for outright cessation of an approved IRP Plan, but would not seek OEB approval to spend less than previously approved amounts.

Findings

The OEB recognizes that material changes may occur that could impact Enbridge Gas's determination as to how best to meet a system need. These may include changes occurring when implementing an IRP Plan after receiving project approval. The OEB believes that updates of this nature are encompassed in the information that the OEB is requiring Enbridge Gas to include as part of its annual IRP report (see chapter 14, "Monitoring and Reporting"). If Enbridge Gas plans to increase its spending on an approved IRP Plan by more than 25%, it will need to request OEB approval for the change, as discussed in chapter 13 ("Future IRP Plan Applications").

9 ALLOCATION OF IRP RISKS

There are risks associated with the development of an IRP Plan and the selection of projects to address constraints. The OEB has identified three significant categories of risk that need to be addressed in developing the IRP Framework.

First, has the IRP Assessment Process accurately assessed the system constraint and evaluated alternative IRPAs or infrastructure builds (Plan Accuracy)? Second, if an IRPA is recommended and approved, will it deliver the reduction to load required to eliminate the constraint (Success of IRP Plan Implementation)? Finally, will the potential stranding of assets currently considered for pipeline infrastructure also apply to IRPAs if the load does not materialize (Potential Stranding of Assets)?

Plan Accuracy

The lack of a comprehensive assessment of alternatives to infrastructure builds has been a risk identified several times in recent OEB Leave to Construct decisions. Several parties raised a concern that by the time Enbridge Gas brings forward an application for a facility project or IRP Plan there may be limited options for the OEB if it concludes Enbridge Gas has not chosen the best option to meet a system need. There is a risk that it would no longer be possible to implement alternative options without compromising safety or reliability. Enbridge Gas indicated that this risk will be low if Enbridge Gas follows its proposed planning framework, including its IRP Assessment Process, annual status updates to its AMP, and consideration of stakeholder feedback.

Enbridge Gas acknowledged that it bears the risk that the OEB might not approve an as-filed Leave to Construct application if the OEB determines that an IRP Plan would have been a better approach. Several parties submitted that, in this circumstance, the OEB may approve something less than full cost recovery.

Success of IRP Plan Implementation

Enbridge Gas submitted that it should not bear the risk that an approved IRP Plan may not succeed in creating the forecast peak demand reduction, as IRP is a new activity, and it is being pursued for the benefit of Enbridge Gas's ratepayers.[58]

Enbridge Gas submitted that if an IRP Plan does not meet expectations, and therefore it needs to be expanded, or where facilities need to be built notwithstanding the IRP Plan,

[58] Argument-in-Chief, p. 18

then the costs of the additional activities should also be paid by ratepayers. Enbridge Gas argued that, due to the greater uncertainty associated with IRP, if it is at risk for lower-than-expected results from IRP Plans, then it will essentially be penalized for pursuing IRP.

Environmental Defence supported the general principle that Enbridge Gas should not end up bearing more risk for IRP Plans than it does for traditional infrastructure projects.

Several parties disagreed with the treatment of risk allocation for IRP Plans as framed by Enbridge Gas, with these parties indicating that Enbridge Gas should bear some risk for the performance of IRP Plans, as it does for facility projects. Some parties tied this to Enbridge Gas's request to earn a rate of return on IRP Plan costs (chapter 12, "IRPA Cost Recovery and Accounting Principles"), indicating that earning a rate of return should require Enbridge Gas to assume a degree of risk. In reply, Enbridge Gas argued that taking the risk of whether an IRP Plan will deliver all the forecast peak demand reductions is not the same as taking the risk that a facility will operate as designed. Enbridge Gas submitted that IRP is a new activity and the peak demand reductions that may be achieved through IRP Plans are much less certain than what will be achieved through facility investments.

Other parties indicated that the risk Enbridge Gas bears for IRP Plan implementation can be addressed through the OEB's prudence review of actual incurred IRP Plan costs. OEB staff submitted that the OEB's prudence review could also take into consideration whether Enbridge Gas had taken appropriate action to adjust its investments in approved IRP Plans as needed, based on its implementation, evaluation and monitoring of "in-flight" IRP Plans. OEB staff suggested that the IRP Framework could acknowledge that there may be a greater degree of performance and cost risk associated with IRP as a new activity, in comparison with facility projects, and that the OEB would take this into account in its prudence review.

Potential Stranding of Assets

SEC raised the potential for stranded assets with IRPAs approved through an IRP Plan. In developing facility projects or IRP Plans, SEC submitted that Enbridge Gas should ensure that they address the risk that assets will be stranded, including active steps to mitigate that risk, and scenario analysis to ensure that the plans will remain robust in the face of that risk.

Findings

Plan Accuracy

The OEB acknowledges the concern that previous Leave to Construct applications have not adequately considered alternatives to the infrastructure build. This IRP Framework and the planned pilots are expected to reduce the risk of inadequate consideration of alternatives. The IRP Assessment Process (including needs identification, binary screening, and evaluation of alternatives), stakeholdering, and experience gained through pilots should result in more prudent and effective integrated resource system planning.

The OEB finds that Enbridge Gas is making considerable effort to improve its planning process, and this is expected to reduce the risk of not developing alternatives that are superior to facility projects where appropriate.

As noted in chapter 8 (“IRP Assessment Process”), the OEB is not requiring Enbridge Gas to seek approval for the results of its IRP Assessment Process prior to project-specific applications for approval of an IRP Plan or a Leave to Construct. Enbridge Gas has considerable experience with Leave to Construct applications, including circumstances in which conditions of approval or modifications made to the original request have been required by the OEB. Furthermore, the OEB retains the authority to deny recovery of costs if it determines that Enbridge Gas was not prudent in considering alternatives, and Enbridge Gas acknowledged this possibility.

Success of IRP Plan Implementation

The OEB finds that prudently incurred costs associated with an approved IRP Plan will be eligible for cost recovery.

The OEB acknowledges that there may be a greater degree of performance and cost risk associated with IRPAs and IRP Plans in comparison with facility projects. Enbridge Gas has extensive experience with the successful implementation of facility projects, and the nature of these types of projects means that the outcome is largely in Enbridge Gas’s control. There is less experience in addressing system constraints using IRPAs like geotargeted DSM or demand response, and these IRPAs depend on consumer behaviour for success. The OEB expects to take this into consideration in its prudence review. However, where Enbridge Gas does not act prudently and in accordance with an approved IRP Plan, then it may be at risk for recovery of some portion of IRP investments that are deemed imprudent.

As Enbridge Gas gains experience with IRP Plans and IRPAs, the risk of non-performance is expected to diminish. When seeking cost recovery, the explanation of what was done to mitigate the risk, and what portion of the risk should be allocated to customers (e.g., by allowing recovery of cost overruns), will require careful review by the OEB.

Potential Stranding of Assets

The risk of stranded assets is a concern for both infrastructure builds and for IRPAs. The OEB has limited experience with the treatment of stranded assets. The examination of the treatment of stranding of assets in other jurisdictions and the findings of the Technical Working Group on this topic might help provide a better understanding of stranded assets and options to allocate the costs between Enbridge Gas and its customers. At this time, the OEB will continue to emphasize the demonstration of prudence by Enbridge Gas, at both the system planning and project planning levels, when addressing the allocation of stranded costs.

10 STAKEHOLDER OUTREACH AND ENGAGEMENT PROCESS

Enbridge Gas requested approval of a proposed three-component stakeholdering process, including a purpose-specific stakeholder Technical Working Group to support IRPA development and to identify and discuss new IRP solutions and IRP avoided costs and benefits.[59]

Enbridge Gas's proposed three-component process includes:

1. Gathering of Stakeholder Engagement Data and Insight: Seeking insights from stakeholders and various market participants by working within existing stakeholder engagement channels, on an ongoing basis, to mitigate incremental expenses and leverage existing relationships.
2. Stakeholder Days: Annual regional stakeholder events focused on IRP to discuss plans and progress with IRP, including specific discussion of needs/constraints identified in the AMP and the plans to address such items through IRP. These would be held on an annual basis shortly after Enbridge Gas files its AMP update within Phase 2 of the annual rates proceeding.
3. Targeted Engagement: Project-specific consultation dealing with specific IRPAs or IRP Plans (identified for a specific need in a specific geographic region), with stakeholders from the specific geographic area relevant to the IRPA. Enbridge Gas also noted that it intends to consult with any potentially impacted Indigenous group in relation to proposed IRP Plans, IRPAs and Leave to Construct applications. Project-specific consultation would be done in advance of seeking project approval from the OEB.

Enbridge Gas's stakeholdering proposal includes a commitment to record comments from stakeholders and Indigenous groups participating in components 2 and 3 and the responses from Enbridge Gas to these comments, which would be filed in any subsequent IRP Plan/Leave to Construct application.

In addition, Enbridge Gas supported the creation of a purpose-specific Technical Working Group comprised of interested parties to have discussions regarding IRP issues of more general interest. Topics that might be addressed include potential IRPAs, determination of the best approach to consider avoided costs and benefits for IRPAs and Facility Alternatives, and the development of natural gas IRP in other

[59] Argument-in-Chief, p. 14

jurisdictions. A first area of focus for the Technical Working Group would be to provide input on the consideration and implementation of IRP pilot projects. Enbridge Gas proposed that it would lead the Technical Working Group.

Enbridge Gas indicated that it does not support any approach to stakeholdering that would give stakeholders a “vote” in system planning decisions.

Three Component Stakeholder Approach

Views were mixed on Enbridge Gas’s proposed stakeholdering approach. Many parties supported Enbridge Gas’s proposed approach. Those parties that believed Enbridge Gas’s stakeholdering approach to be insufficient generally indicated a preference for greater stakeholder involvement (e.g. the ability to ask interrogatories, OEB adjudication in the event of disputes) in Enbridge Gas’s determinations regarding specific planning decisions, such as screening out IRPAs for system needs, prior to seeking approval from the OEB for specific projects. In reply, Enbridge Gas indicated that it does not agree with stakeholder proposals for more regulatory process and ongoing OEB oversight throughout the stakeholdering process. The OEB’s findings regarding the OEB role in planning decisions made by Enbridge Gas prior to applications are discussed in chapter 8 (“IRP Assessment Process”).

Anwaatin raised issues specific to engagement and consultation with Indigenous peoples, including Duty to Consult requirements. These issues are discussed separately in chapter 11 (“Indigenous Engagement and Consultation”).

Several parties provided suggestions designed to ensure that all interested stakeholders, including low-income customer representatives, were aware of Enbridge Gas’s stakeholdering activities and were able to participate. In reply, Enbridge Gas agreed to creating a list of interested parties and ensuring that all such parties receive notice of stakeholdering activities. Enbridge Gas suggested that an IRP dedicated web page would be the most efficient way to inform stakeholders.

OEB staff supported Enbridge Gas’s proposal to keep a written record of consultation activities to inform future project-specific decisions. Pollution Probe suggested that the IRP webpage could also include similar information (aligning with IESO practices), such as presentations and meeting minutes. Enbridge Gas indicated that it was open to this proposal.

Technical Working Group

Most parties supported the establishment of an IRP Technical Working Group, but indicated a preference for the OEB to lead the group, similar to the approach used with the OEB's Demand-Side Management Evaluation Advisory Committee. In its reply argument, Enbridge Gas disagreed, indicating that the purpose of the proposed IRP Technical Working Group was to provide Enbridge Gas with guidance and perspective from expert advisors to determine the appropriate direction and approach for IRP process and decisions.

OEB staff and SEC made recommendations for the focus of the Technical Working Group that were similar to Enbridge Gas's proposal. OEB staff listed the following topics on which the Technical Working Group could potentially provide input to the OEB and Enbridge Gas:

- Consideration and implementation of IRP pilot projects
- Cost-benefit considerations regarding IRPAs
- Learnings on specific types of IRPAs, and IRP implementation in other jurisdictions
- Accounting treatment of IRPA costs

GEC submitted that the Technical Working Group should be mandated to make recommendations to the OEB for changes to the IRP Framework where the Technical Working Group determines such changes are needed.

Some parties proposed a different role for the Technical Working Group (or additional groups) with more focus on contributing to or reviewing the specific system planning determinations of Enbridge Gas. For example, EFG's expert evidence recommended a model similar to the Vermont System Planning Committee, which has a greater emphasis on reviewing specific system needs and determining the optimal solution, including voting rights to document positions on issues. GEC proposed that the Technical Working Group would review all IRP screening decisions and report annually to the OEB. Enbridge Gas objected to these proposals, indicating that they inappropriately seek to transfer oversight and direction for IRP system planning decisions from Enbridge Gas to stakeholders.

Some parties made recommendations for membership on the Technical Working Group (in addition to membership of Enbridge Gas and OEB staff), with suggestions including representatives of Indigenous customers, environmental groups, consumers, low-income customers, the IESO or electricity distributors/transmitters, and IRPA service providers.

Findings

The OEB has determined that the three components of Enbridge Gas's proposed Stakeholder Engagement Process will provide valuable input into Enbridge Gas's IRP activities and shall be incorporated in the IRP Framework. The OEB also directs the establishment of a website by Enbridge Gas to facilitate the broad sharing of information on IRP stakeholdering efforts.

In addition to the three component stakeholder process, the OEB will also establish an IRP Technical Working Group led by OEB staff. This will be similar to the widely endorsed and successful Demand-Side Management Evaluation Advisory Committee. Leadership by OEB staff will promote objectivity and impartiality. The IRP Technical Working Group will have an objective of providing input on IRP issues that is of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework. The IRP Technical Working Group is being established for the first-generation IRP Framework; continuation of a Technical Working Group for next generations will be reassessed based on the needs at that time. It is expected that IRP will become a routine matter of planning within Enbridge Gas over time.

OEB staff will establish a terms of reference and select the membership. The OEB expects that the first priorities will be consideration and implementation of the IRP pilot projects, and enhancements or additional guidance in applying the DCF+ evaluation methodology. The OEB agrees with the suggestion that IRP progress in other jurisdictions should continue to be monitored. This may be a consideration for the Technical Working Group once the initial priorities have been addressed.

The IRP Technical Working Group will also be expected to review a draft of Enbridge Gas's annual IRP report, with the review coordinated by OEB staff. Enbridge Gas should provide a draft of the annual IRP report to the IRP Technical Working Group far enough in advance of its planned filling to the OEB to allow the Technical Working Group time to review and comment. A report from the Technical Working Group to the OEB should be filed by OEB staff in the same proceeding in which Enbridge Gas's annual IRP report is filed. The Technical Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Technical Working Group, and may also describe other activities undertaken by the Technical Working Group in the previous year.

One topic that should be addressed by the IRP Technical Working Group in the future is the recommendation of IRP metrics for the OEB's consideration, as noted in chapter 14 ("Monitoring and Reporting"). Other topics could include the treatment of stranded assets in other jurisdictions, as noted in chapter 9 ("Allocation of IRP Risks").

As Enbridge Gas noted, under the Ontario regulatory model, Enbridge Gas is the natural gas system operator with the sole responsibility to make final system planning decisions and to advance IRP Plans and/or Leave to Construct applications. Enbridge Gas does not support the Technical Working Group having "voting rights" and the OEB agrees with this position. While Enbridge Gas is expected to consider any input provided by the Technical Working Group, the Technical Working Group will not have "voting rights" that bind Enbridge Gas with regards to its system planning decisions.

Enbridge Gas submitted that parties included in the IRP Technical Working Group should have relevant demonstrable technical expertise that relates to and informs the activities to be addressed by the IRP Technical Working Group. The OEB agrees with this recommendation. The OEB directs that membership should include Enbridge Gas, OEB staff, independent experts, and experienced non-utility stakeholders. Membership may also include the Independent Electricity System Operator, if appropriate. Beyond this, the OEB is not establishing requirements for representation of specific interests on the Technical Working Group, as recommended by some parties. Selection should be based on the value that potential members can bring to implementing and improving the IRP Framework and Enbridge Gas's IRP activities under the Framework. The IRP Technical Working Group will need to be kept to a manageable size to ensure timely and effective consultation. The OEB expects there should be no more than 10 people.

The OEB has concluded that establishing the Technical Working Group is a priority and must be established shortly after this IRP Framework is issued. OEB staff will establish the IRP Technical Working Group, including a terms of reference, and the initial selection of Working Group members, by the end of 2021.

11 INDIGENOUS ENGAGEMENT AND CONSULTATION

Anwaatin submitted that, in the development of its IRP proposal, Enbridge Gas failed to carry out Indigenous consultation and engagement. Anwaatin requested that the OEB find that Enbridge Gas failed to comply with the Indigenous People's Policy[60] of Enbridge Inc. (the parent company of Enbridge Gas) in relation to the proposed IRP Framework, and require it to do so. In reply, Enbridge Gas submitted that, in its view, the duty to consult was not triggered by the IRP proposal itself as the OEB's decision in this proceeding does not contemplate conduct that may adversely impact asserted or established Aboriginal or treaty rights.[61] Enbridge Gas also submitted that, regardless of whether the duty to consult has been triggered by this proceeding or whether Aboriginal consultation is required, Anwaatin has been a full participant in the current proceeding, and Enbridge Gas has carefully considered its views.

Going forward, Anwaatin requested that the OEB direct Enbridge Gas to conduct Indigenous-specific engagement in advance pursuant to each of the three stakeholdering components to ensure that there is an opportunity for Enbridge Gas to engage proactively in a considered and meaningful two-way dialogue with affected Indigenous communities.[62] Anwaatin also submitted that Enbridge Gas's stakeholder outreach and engagement process should demonstrate a stronger adherence and commitment to the Indigenous Peoples Policy, the United Nations Declaration on the Rights of Indigenous Peoples, and the duty to consult and accommodate.

In response to Anwaatin's submissions, Enbridge Gas submitted that it is committed to engaging with Indigenous peoples, in accordance with its Indigenous Peoples Policy and the duty to consult and accommodate, where applicable and where the procedural aspects have been delegated to Enbridge Gas. Enbridge Gas indicated that it would specifically consult with Indigenous communities with the potential to be affected by any IRPA investments selected, in accordance with the duty to consult.

Enbridge Gas also stated that it would follow the process for Indigenous consultation set out in the OEB's *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario* (the Environmental Guidelines) for both facility and non-facility alternatives. OEB staff submitted that it was not clear whether all of the provisions of the Environmental Guidelines are a good fit for non-

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[60] Available online at: https://www.enbridge.com/~/media/Enb/Documents/About%20Us/indigenous_peoples_policy.pdf?la=en
[61] Enbridge Gas reply argument, pp. 15-16
[62] Anwaatin submission, pp. 14-19

facility alternatives (including the Indigenous consultation chapter of these Guidelines, which includes a significant role for the Ministry of Energy, Northern Development and Mines that may not apply to non-facility projects).[63]

Findings

The OEB does not find that Enbridge Gas failed to comply with the Indigenous People's Policy[64] of Enbridge Inc. The Enbridge Inc. policy limits the consultation to projects that may occur on lands traditionally used by Indigenous Peoples. More importantly, with respect to the duty to consult with Indigenous Peoples, the OEB's role is to determine if the duty has been triggered, and if so, whether the duty has been satisfied. It is not the OEB's role to enforce the implementation of a utility's internal policies that may not have been developed to satisfy external requirements.

Anwaatin submitted that the duty to consult is not limited to projects that have an immediate impact on land and resources but extends to "strategic, higher level decisions", such as the proposed IRP Framework. The OEB recognizes that the duty to consult may arise with respect to high-level managerial or policy decisions. However, this would require an identifiable potential adverse impact to an Aboriginal or treaty right. Neither Anwaatin, nor any other party, have identified any specific Aboriginal or treaty rights that could be adversely impacted through the creation of this IRP Framework.

In its decision in Enbridge Gas's RNG Enabling proceeding,[65] the OEB found that the duty to consult did not apply under the test set out in the Carrier Sekani case.[66] In coming to that conclusion, the OEB noted that there were no projects or even areas for future development being approved. Similarly, in this Decision and Order on the IRP Framework, no projects have been defined and no approval is being given for the

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[63] OEB staff argument, pp. 39-40
[64] Available online at:
https://www.enbridge.com/~/media/Enb/Documents/About%20Us/indigenous_peoples_policy.pdf?la=en
[65] Application for the Renewable Natural Gas Enabling Program, EB-2017-0319, Decision and Order, October 18, 2018
[66] In *Carrier Sekani*, the Supreme Court of Canada summarized the three elements that are required for the Duty of Consult to be triggered. Briefly these are: the Crown must have real or constructive knowledge of a claim to the resource or land; there must be Crown conduct or a Crown decision that engages a potential Aboriginal right; the claimant must show a causal relationship between the proposed government conduct or decision and a potential for adverse impacts on pending Aboriginal claims or rights. *Rio Tinto Alcan Inc. v. Carrier Sekani Tribal Council*, 2010 SCC 43, paragraphs 40 to 45.

development of an IRP Plan. Once again, the OEB does not find any direct material impact that this Decision and Order will have on any Aboriginal or treaty rights.

The IRP Framework is being established by the OEB with input from many stakeholders including an Indigenous representative intervenor. Anwaatin has actively participated in this proceeding and made a submission on the issues and perspectives of Indigenous Peoples. The views presented have been heard and actively considered by the OEB.

Anwaatin also requested that the OEB direct Enbridge Gas to conduct Indigenous specific engagement in advance of each of the three IRP stakeholdering components to ensure that there is a meaningful two-way dialogue with affected Indigenous communities. The OEB finds this request to be too broad, and will not require Indigenous-specific engagement as a mandatory element for each of the three stakeholdering components in the IRP Framework in every case. Enbridge Gas has indicated that it will make efforts to accommodate participation of Indigenous groups within its stakeholder engagement process and work with these groups as appropriate to address any concerns. The OEB endorses this approach and expects that Indigenous engagement will take place in cases where material Indigenous interests are engaged.

There is insufficient information on the record at this time to determine which Indigenous communities would be impacted by specific system needs and the potential solutions (IRP Plans or facility projects), and what impact, if any, the individual IRP Plans might have on Aboriginal or treaty rights. In addition to any broader stakeholder engagement with Indigenous groups, Enbridge Gas is required to conduct consultation with respect to any potential impacts to Aboriginal or treaty rights in relation to proposed IRP Plans (which may include the individual IRPAs considered) and Leave to Construct applications. Any concerns can be considered on a case-by-case basis when an IRP Plan or a Leave to Construct application comes before the OEB for approval.

When Enbridge Gas requests approval for an IRP Plan or a Leave to Construct, it will be necessary for Enbridge Gas to follow the requirements in the Environmental Guidelines regarding Indigenous consultation, if applicable.

12 IRPA COST RECOVERY AND ACCOUNTING TREATMENT PRINCIPLES

Enbridge Gas requested approval of like-for-like treatment of IRPA investments, such that longer term investments in IRP Plans will be capitalized as rate base, with cost recovery similar to the facility investments that they are replacing at the time of in-service (with IRPA costs amortized over their useful lives).[67]

Enbridge Gas submitted that it is reasonable and appropriate to treat costs (capital expenditures and operating expenditures) associated with planning, implementing, administering, measuring and verifying the effectiveness of its investments in IRPAs in the same manner as the costs for the facility expansion/reinforcement projects that IRP would defer, avoid or reduce, by capitalizing these costs to rate base.

Enbridge Gas defined three categories of costs associated with IRP implementation and identified its proposed cost treatment for each category:[68]

- <u>Incremental IRP administrative costs</u> required to meet the increased workload related to IRP. Enbridge Gas proposed that incremental IRP administrative costs be included in the Operating, Maintenance, and Administrative (OM&A) costs of its revenue requirement. While Enbridge Gas indicated that it is difficult to say with certainty what additional resources will be required at this time to support IRP, Enbridge Gas estimated that it will need roughly 12 to 15 additional full-time equivalents to integrate IRP into its planning processes, complete the incremental stakeholdering, assess identified system constraints for IRPA(s), and complete necessary IRP Monitoring and Reporting.[69]

- <u>IRPA Project costs</u> including the planning, implementing, administering, measuring and verifying the effectiveness of specific investments in IRPAs. Enbridge Gas proposed that the IRPA project-related costs be capitalized to rate base, and eligible for cost recovery once a project is in-service.

- <u>Ongoing operational and maintenance costs</u> including the regular costs incurred to operate and maintain a specific IRPA investment after the project is in-service. Enbridge Gas proposed that the costs related to the ongoing operating maintenance of an IRPA be included in Enbridge Gas's OM&A costs of its

[67] Argument-in-Chief, p. 14
[68] Exhibit I.Staff.22
[69] Exhibit I.GEC.6

revenue requirement.

Enbridge Gas indicated that it believes existing accounting guidance is generally clear regarding the distinction of these cost categories, but that additional clarity could be sought if needed in the context of a specific IRP Plan application.[70] Enbridge Gas submitted that the details of which specific costs qualify to be treated as capital investments, and what asset life applies, could be addressed in an IRP Plan application. However, the IRP Framework should indicate the general principles that should apply to the cost treatment of IRP investments.

For some IRPAs, Enbridge Gas will make an investment in assets that it will own and operate, or programs that it will deliver. For other IRPAs, for example equipment or services available from the competitive market, Enbridge Gas will make an enabling payment to a service provider but will not own or operate any tangible asset. In those cases, Enbridge Gas proposed to treat the cost of the enabling payments or incentives made as a regulatory asset that would be added to rate base.[71] This could potentially apply to both demand-side and supply-side IRPAs. Enbridge Gas indicated that if capitalization might not be a workable approach for specific IRPAs (perhaps shorter-term solutions), it could bring forward an alternative accounting treatment within the context of an IRP Plan application.[72] Enbridge Gas acknowledged that its proposal to capitalize IRPA costs is different than the treatment of energy efficiency costs in the DSM Framework (which allows Enbridge Gas to recover costs on an annual basis with the possibility of a performance-based shareholder incentive, but does not include capitalization of costs) but submitted that this difference is appropriate because of the different purposes of DSM and IRP.

Enbridge Gas indicated that it follows U.S. Generally Accepted Accounting Principles (GAAP), which allows regulated entities to capitalize costs that would otherwise be expensed, if Enbridge Gas can demonstrate that it is probable that the costs will be recovered through future revenues derived from rates approved by the OEB (e.g. through a rate order). In this case, Enbridge Gas believes that regulatory rate base and audited financial statements would be aligned.[73]

Enbridge Gas indicated that it believes the cost recovery aspect of its IRP proposal could proceed independently of the ongoing OEB policy consultations on Utility

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[70] Technical Conference Transcript, Day 2, p. 205.
[71] Transcript from day 3 of oral hearing, pp. 37-41, Argument-in-Chief, p. 38
[72] Transcript from day 3 of oral hearing, pp. 104-108
[73] Exhibit J 3.7; Transcript from day 3 of oral hearing, pp. 145-147

Remuneration and Responding to Distributed Energy Resources.[74] On March 23, 2021, the OEB combined these consultations under the new title Framework for Energy Innovation (FEI): Distributed Resources and Utility Incentives (EB-2021-0118).[75] The OEB issued a letter about FEI after the record closed for this proceeding. This letter indicated that near-term workstreams will be focused on usage and integration of distributed energy resources, although the letter indicated that issues relating to utility remuneration would likely be considered in subsequent phases.[76]

Many parties supported the principle of Enbridge Gas's proposal for like-for-like cost treatment and agreed that this would remove a disincentive for Enbridge Gas to pursue IRP. Expert evidence from Guidehouse and EFG also supported the general principle of like-for-like treatment of IRPA investments. Guidehouse noted that Consolidated Edison in New York State is proposing a similar approach to capitalizing its future investments in IRPAs.

However, some parties argued that deciding on the capitalization treatment at this stage was premature, and that the OEB should wait until reviewing specific IRP Plan applications to decide on the capitalization treatment. Several parties indicated that their support for Enbridge Gas to earn a rate of return was conditional on the OEB's treatment of risk for IRP Plans. For example, CME proposed that ratepayers should only pay for investments from which they are deriving a benefit, and that the OEB could assess Enbridge Gas's potential recovery of those investments on the 'used and useful' test basis, to protect ratepayers from having to pay for unproductive or useless assets, if the IRP Plan did not deliver the benefits that were forecast.[77]

Several other parties (APPRO, LPMA, SEC) opposed Enbridge Gas's proposal and raised concerns that placing assets in rate base can create an unfair playing field with non-regulated providers of IRPAs. This concern was also raised in letters of comment submitted by the Ontario Geothermal Association and Diverso Energy, specifically with regard to the potential for Enbridge Gas to own and put into rate base geothermal systems as an IRPA.

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[74] Technical Conference Transcript, Day 2, p. 206
[75] Letter Re: Framework for Energy Innovation: Distributed Resources and Utility Incentives (EB-2021-0118), March 23, 2021
[76] Letter Re: Framework for Energy Innovation: Distributed Resources and Utility Incentives (EB-2021-0118), May 10, 2021
[77] CME Final Argument, pp. 18-21

SEC argued that normal accounting treatment for IRP costs should be followed, although exceptions could be granted on a case-by-case basis. SEC also noted that there was a potential risk of stranded assets applied to costs in rate base, for either IRPAs or facility projects. FRPO noted that while a utility company receives the benefits of being a monopoly provider with an opportunity to make a return on capital investments, there are utility costs that are incurred to provide safe and reliable service which are paid for in rates as expenses but do not generate additional return. FRPO indicated that solutions such as the Parkway Delivery Obligations have reduced facility investment and have been in place for years without Enbridge Gas receiving shareholder incentives or capitalization, and that capitalizing all IRPA costs would not be appropriate.

Enbridge Gas noted several objections to the suggestion that IRP costs should generally be expensed. First, it could lead to volatile rates, particularly in the first years of IRP implementation. Second, it could cause intergenerational inequity. Third, it ignores that other jurisdictions have adopted like-for-like treatment and capitalization of non-wires/non-pipes solutions. Finally, expensing IRP costs provides no incentive to the utility for pursuing IRP. When the utility engages in its traditional role of providing safe and reliable service, it is compensated for its capital investments. Enbridge Gas submitted that it is not a balanced approach to direct the utility to pursue alternate activities from those of its traditional role while at the same time indicating that there will be no compensation for pursuing the alternate activities that are being prescribed.

Additional/Alternative Incentive Mechanisms

The expert evidence of Guidehouse and EFG discussed the possibility of additional or alternative incentive mechanisms for Enbridge Gas to pursue IRP. Enbridge Gas indicated that it was open to considering additional incentives, but that it was not proposing such incentives as part of its IRP proposal, and that, in its view, the simplest way to create a level playing field between IRPAs and facility investment projects was to ensure that Enbridge Gas is equally incented between the two types of investments, through the proposed treatment to rate base IRPA costs. Should the OEB wish to prioritize investments in IRPAs, Enbridge Gas submitted that it could consider adding an incentive above rate of return (e.g. based on the net benefits achieved, in comparison with a facility project). However, this topic of incentives could be studied at a future date.[78]

[78] Exhibit B, pp. 33-34, Exhibit I.Staff.25

Parties commenting on this topic generally did not support additional incentives for IRP, or felt it premature to include them in the IRP Framework at this time.

Enbridge Gas's position on incentives was tied to its proposal that it be eligible for recovery of all prudently incurred costs associated with IRPAs, and that ratepayers bear the performance risk associated with IRPAs. Enbridge Gas noted that, if the IRP Framework requires Enbridge Gas to bear additional risk associated with IRPAs, then Enbridge Gas would expect that commensurate adjustment to its allowed return on equity and/or incentives for such investments would be necessary to account for the heightened risk profile taken on by Enbridge Gas.[79]

Findings

The OEB finds that IRPA project costs, similar to the costs for infrastructure builds, should be eligible for inclusion in rate base where Enbridge Gas owns and operates the IRPA. Enbridge Gas should include 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. Until rebasing, the associated revenue requirement of these project costs will be recorded in a capital costs deferral account for recovery annually or at rebasing as requested by Enbridge Gas.

Where Enbridge Gas proposes to make an enabling payment to a competitive service provider and does not own or operate the asset, these costs, if approved, will be included in the category of ongoing operational and maintenance costs and recovered as operating expenses. Notwithstanding concerns expressed about a potential unfair playing field with non-regulated providers of IRPAs, the OEB requires that Enbridge Gas select the most efficient and cost-effective option for its customers, between Enbridge Gas ownership and third-party ownership with an enabling payment. Until rebasing, these operating costs will be recorded in an operating costs deferral account for recovery annually or at rebasing as requested by Enbridge Gas. Incremental IRP administrative costs and other ongoing operational and maintenance costs will also be treated as expenses and recorded in this account.

The OEB finds that the inclusion in rate base for owned and operated IRPAs in this first-generation IRP Framework is preferred given its relative simplicity.

The consultations under the FEI are at an early stage with the development of terms of reference and initial meetings for the FEI working group. While the FEI consultation is

[79] Exhibit I.EP.6

likely to address matters of utility remuneration in subsequent phases, the first-generation IRP Framework will proceed before any determinations have been made. The OEB is therefore providing guidance on the approach to recovery of costs for the first-generation IRP Framework.

The IRPA project costs eligible for inclusion in rate base will attract the same cost of capital as other rate based assets for Enbridge Gas. The depreciation period for the IRPA assets will align with the expected useful life of the asset, which will likely be the time over which the underlying IRPA is expected to provide peak load reduction.

Details about how these principles will be applied to specific IRPAs and IRP Plans will be determined in the IRP Plan applications. As part of an IRP Plan application, Enbridge Gas should provide details on which IRP Plan costs it believes are eligible for inclusion in rate base, versus those that should be considered operating expenses, with supporting rationale. Details on recovery of IRP Plan costs through the IRP Costs deferral accounts, including the number of deferral accounts, elements to be included in the deferral accounts and method of recovery of approved deferral account costs are covered in chapter 15 (“IRP Costs Deferral Accounts”).

The OEB concludes that it is premature to develop an incentive mechanism or offer additional incentives as part of the first-generation IRP Framework. As more is learned though the pilots, the FEI, or experience in other jurisdictions, consideration of incentives may be part of the assessment of an IRP Plan on a case-by-case basis. This would require a detailed assessment of the risk of the IRPA compared to the risk premium already included in the approved return on equity.

13 FUTURE IRP PLAN APPLICATIONS

Enbridge Gas requested a new OEB approvals process, similar to the Leave to Construct approvals process used for facility projects, to review and approve a proposed IRP Plan designed to meet an identified need/constraint.[80]

Enbridge Gas indicated that it is seeking to establish similar assurances for investments in natural gas IRPA(s) as the OEB Act (under sections 90 and 91) affords natural gas utilities through Leave to Construct applications for facility projects, assuming associated costs of investment in IRPA(s) have been incurred prudently.[81]

Legal Basis for IRP Plan Approval and Required Information

Under section 90 of the OEB Act[82], an order from the OEB is required for leave to construct hydrocarbon pipelines that meet certain criteria relating to size, length, cost, or operating pressure. This legislative requirement is the basis for the existing Leave to Construct approval and parties agreed that it does not apply to IRP Plans.

Enbridge Gas indicated that the new IRP Plan approval could presumably be made under section 36 of the OEB Act, on the premise that the investments being made are in place of natural gas infrastructure and are aimed at ensuring that Enbridge Gas continues to provide safe, reliable gas delivery service to its customers. Section 36 of the OEB Act requires that sales of gas or charges for the transmission, distribution or storage of gas must be in accordance with an order of the OEB.

Enbridge Gas proposed to make IRP Plan applications to the OEB in the future in all instances where the total cost of IRP Plans exceeds the cost threshold that triggers a mandatory Leave to Construct approval for pipeline projects. This threshold is currently $2 million, although the Ontario government has proposed a change to the relevant regulation that would increase the threshold to $10 million.[83] IRP Plan applications below this threshold would be at Enbridge Gas's discretion, but Enbridge Gas indicated that it would likely seek OEB approval of all IRP Plans (including IRP pilot projects), at least in the initial stages of IRP.

[80] Argument-in-Chief, p. 14
[81] Argument-in-Chief, p. 41
[82] Section 91 of the OEB Act provides that before constructing a hydrocarbon line to which section 90 does not apply, an application may be made to the OEB for an order granting leave to construct.
[83] Environmental Registry Proposals 019-3041, 019-4029. The materiality threshold is specified in O.Reg. 328/03 under the OEB Act.

Enbridge Gas indicated that it expects that its IRP Plan application would include information similar to what is found in a Leave to Construct application, including purpose, need and timing type evidence (such as the forecast need/constraint being addressed, description of the IRPAs, forecast impacts from the IRPAs, costs of the IRPAs, and implementation timing), discussion of alternatives (why the IRP Plan was selected), land and environmental issues (where relevant), Indigenous consultation (as appropriate) and conditions of approval.[84] Enbridge Gas indicated that, while the IRP Plan approval would not itself be the mechanism for cost recovery, it might be appropriate for the OEB to invite submissions on Enbridge Gas's proposed cost allocation treatment within the IRP Plan approval process, because that could influence the positions of parties. Enbridge Gas proposed that the default cost allocation approach for an IRP Plan would generally be the same cost allocation approach as would have been used for the facility project that would otherwise have been needed.

Most commenting parties agreed with or did not oppose the proposal for a new IRP Plan approval and agreed that section 36 of the OEB Act provided the OEB with the necessary authority for this approval, particularly if (as recommended by OEB staff and APPRO) the application addressed issues such as the proposed approach to cost recovery and cost allocation and provided information on expected bill impacts. OEB staff also supported Enbridge Gas's proposal that the default approach to rate class allocation for an IRP Plan should be the same as would have been used for the facility project that would otherwise have been needed.

In its reply submission, Enbridge Gas agreed that this information should be included in an IRP Plan application, and submitted that the OEB could approve the cost consequences of a proposed IRP Plan under section 36 of the OEB Act, with that approval operating as an endorsement of the underlying IRP Plan.

Anwaatin disagreed, raising concerns that the IRP Plan approval is currently not authorized by sections 36, 90, 91, or 92 of the OEB Act.[85]

In addition to the information on cost recovery and cost allocation, OEB staff recommended adding a record of stakeholder and Indigenous groups engagement, as well as a proposed approach to evaluation and monitoring in each application for IRP Plan approval.

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[84] Argument-in-Chief, pp. 40-41
[85] Anwaatin Inc. Final Argument, pp. 19-20

Adjustments to IRP Plans

Enbridge Gas requested flexibility to adjust an approved IRP Plan without further OEB review except where the costs being adjusted are 25% or greater of the total approved cost.

Several parties disagreed with this proposal. Energy Probe and APPRO suggested a lower cost overrun threshold was appropriate.

OEB staff supported providing Enbridge Gas with flexibility to adjust its investments in approved IRPAs, noting that this was consistent with the expert evidence filed by Guidehouse. Guidehouse recommended that the IRP Framework provide utilities with flexibility to adjust program designs, budgets, implementation plans, and other processes to quickly adapt IRP programs, and noted that this flexibility had been provided by the New York State Public Services Commission for Con Edison's Smart Solutions Program.[86]

However, OEB staff did not support the specific requirement for Enbridge Gas to return to the OEB when the costs being adjusted are 25% or greater of the original cost. OEB staff suggested that including this requirement as part of the Framework implied that cost increases that are less than 25% of the original cost would likely be approved when Enbridge Gas seeks cost recovery. OEB staff instead proposed that Enbridge Gas should have broad latitude to adjust its investments in approved IRP Plans, with the prudence of these adjustments to be reviewed when Enbridge Gas sought cost recovery. Under this approach, Enbridge Gas would always have the option of applying to the OEB to amend an approved IRP Plan if it wanted additional certainty regarding the likelihood of cost recovery.

Incrementality of IRP Plan Costs

OEB staff noted that some IRP Plans may be alternatives to facility projects that would have been implemented during the current deferred rebasing term, and as such, the associated costs would not necessarily be incremental, and would therefore not be eligible for cost recovery.

Enbridge Gas agreed that where an IRP Plan takes the place of a facility project that would have occurred during the current deferred rebasing term, then the associated costs are not necessarily entirely incremental (though they could be eligible for

[86] Guidehouse report, p. 17, 61

Incremental Capital Module treatment). However, Enbridge Gas submitted that where an IRP Plan takes the place of a facility project that would not have been implemented until after the end of the current deferred rebasing period, the associated IRP Plan costs are incremental and eligible for cost recovery in the future through the IRP Costs deferral account.

Findings

The OEB is establishing a new approval process for IRP Plans, as part of the IRP Framework. Regarding its approval authority, the OEB relies on section 36 of the *OEB Act* to approve the cost consequences of a proposed IRP Plan, with an IRP Plan approval operating as an endorsement of the underlying IRP Plan. The costs would then be recovered, subject to a prudence review, through the IRP Costs deferral accounts annually and/or at Enbridge Gas's next rebasing application, as discussed in more detail in chapter 15 ("IRP Costs Deferral Accounts").

OEB staff submitted that as Enbridge Gas gains more experience with IRPAs, it may be the case that an explicit IRP Plan approval would no longer be required, and Enbridge Gas's proposed spending on IRPAs could be reviewed solely within the context of Enbridge Gas's rate applications. The OEB agrees that there may be an evolution in the approval process as more experience is gained. However, the OEB finds that during this first-generation IRP Framework, it is appropriate to give Enbridge Gas assurance of preapproval of an IRP Plan to proceed. An IRP Plan approval will be mandatory if the forecast costs of the IRP Plan exceed the minimum project cost (currently $2 million, proposed to increase to $10 million) that would necessitate a Leave to Construct approval for a pipeline project. The OEB acknowledges that there may be a greater degree of uncertainty associated with IRP as a new activity, in comparison with facility projects, accordingly a preapproval of the IRP Plans is appropriate.

The OEB concludes that the information proposed by Enbridge Gas, with the additions proposed by OEB staff, and a section discussing how the guiding principles for the IRP Framework have been addressed, should be submitted with an IRP Plan approval request. Having a full understanding of not only the IRP Plan and its costs, but also about how those costs will be recovered and the resulting bill impacts, will be helpful to stakeholders and the OEB. The OEB expects that an approach to cost allocation will be part of an IRP Plan approval. The OEB agrees with Enbridge Gas that the approach to allocating costs for the facility project that is being avoided, deferred, or reduced by the IRP Plan will serve as an important reference point for the approach to cost allocation for IRP Plans.

As noted in chapter 12 (“IRPA Cost Recovery and Accounting Treatment Principles”), the information regarding cost recovery should include details on which IRP Plan costs Enbridge Gas proposes for inclusion in rate base, versus those that should be considered operating expenses, together with supporting rationale. This should also include a proposed in-service date, and any considerations that may apply regarding when the IRP Plan should be considered to be in-service such that Enbridge Gas is eligible for cost recovery.

Enbridge Gas proposed that whenever adjustments to an IRP Plan are expected to lead to cost differences of 25% or more of the total OEB approved costs for individual IRPA investments, then Enbridge Gas would apply to the OEB for approval to make the adjustments, but would otherwise have flexibility to adjust the IRP Plan without further OEB review. This flexibility is consistent with the recommendations of Guidehouse as well as its observations of flexibility offered to utilities in New York State. For this first-generation IRP Framework where there is less experience with IRPAs, the OEB agrees to the 25% threshold requirement for seeking approval of changes through an adjustment to an IRP Plan. When seeking recovery of actual IRP Plan costs, Enbridge Gas will need to demonstrate that it has been prudent in managing its actions and resulting costs, as is typical for all requests for cost recovery. As discussed in chapter 9 (“Allocation of IRP Risks”), Enbridge Gas will need to fully demonstrate the prudence of their actions particularly with regard to the risks of successful implementation of IRP Alternatives and the potential for assets becoming stranded.

As discussed in chapter 15 (“IRP Costs Deferral Accounts”), the OEB is establishing deferral accounts to record incremental costs associated with IRP, including IRP Plan costs, during the current deferred rebasing term. The OEB expects that an IRP Plan approval would address the issue of whether IRP Plan costs during this period are considered to be incremental. An IRP Plan application should identify whether Enbridge Gas intends to seek recovery of all or part of the IRP Plan costs, including Enbridge Gas’s rationale as to why these costs are incremental to activities included in existing rates. Whether there will be amendments to these deferral accounts after rebasing will be determined in the rebasing application, taking into consideration what IRP costs have been included in base rates.

The OEB expects that IRP Plan costs would qualify for recovery, subject to a prudence review, as part of the annual deferral account review or during the next rebasing application, The OEB acknowledges that IRP Plan costs may be eligible for recovery sooner than a facility project (unless the facility project met the criteria for an Incremental Capital Module). This is an incentive to encourage IRPA investments.

14 MONITORING AND REPORTING

Enbridge Gas requested approval of the proposed annual IRP reporting from Enbridge Gas that will address IRP integration into existing planning processes, IRPA effectiveness, IRP pilot projects planned or underway, IRP stakeholdering and IRPA implementation.[87]

Enbridge Gas proposed that the annual IRP report would include a summary of IRP stakeholdering, updates on IRP pilot projects, updates on incorporating IRP into AMP, status updates on potential and approved IRP Plans, and summaries of in-flight IRPAs, including expenditures and actual peak demand/energy savings compared to forecast.

Enbridge Gas indicated that the annual IRP report could be filed with the OEB as part of either its annual Rates application or Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application.

Most parties commenting on this issue agreed with the proposal for an annual IRP report and that the items were generally appropriate.

Several parties indicated that it was important that the annual IRP report be subject to stakeholder review, likely through an OEB proceeding. OEB staff suggested that the annual IRP Report be filed in the proceeding where Enbridge Gas proposes to clear the IRP Costs deferral account. Enbridge Gas agreed with that suggestion. Energy Probe requested that Enbridge Gas clarify whether the annual IRP report would be filed for information only or would be approved by the OEB. In reply, Enbridge Gas stated that stakeholders would have the opportunity to ask interrogatories about the annual IRP Report in the proceeding where it is filed, but that it is not necessary or appropriate for the OEB to issue an “approval” for the annual IRP Report. GEC submitted that an annual report from the Technical Working Group should also be part of the IRP reporting.

Several parties also commented on the issue of whether metrics or a scorecard for IRP should be part of the annual IRP reporting. Pollution Probe recommended that the OEB set an initial minimal set of scorecard metrics, while LPMA and APPRO suggested that metrics be established in the context of developing IRP Plans or pilot projects. In reply, Enbridge Gas submitted that it was premature to develop a scorecard or metrics for IRP activities in general, but that Enbridge Gas would not object to specific metrics to

[87] Argument-in-Chief, p. 15

monitor the performance of IRP Plans or pilot projects, which would be determined in an IRP Plan approval.

Findings

The OEB agrees with the key elements of the annual IRP Report proposed by Enbridge Gas including the following:

- A summary of IRP stakeholdering activities from the past year
- A summary of IRP engagement or consultation activities with Indigenous peoples
- Updates on IRP pilot projects underway
- Updates on incorporating IRP into asset management planning
- Updates on status of potential IRP Plans
- Updates on status of approved IRP Plans, including details of adjustments made by Enbridge Gas
- Annual and cumulative summaries of actual peak demand reductions/energy savings generated by each IRP Plan to-date, including comparisons to the initial forecast reduction/energy savings and the actual amount of expenditure on each IRP Plan to-date
- Any other IRP-related matters established by the OEB

As part of its update on incorporating IRP into asset management planning, or its update on the status of potential IRP Plans, Enbridge Gas should include the most recent results of its IRP Assessment Process for system needs, including reporting on those system needs where a negative binary screening or technical/economic evaluation resulted in no further assessment of IRPAs, as discussed in chapter 8 (“IRP Assessment Process”). Reporting from the Technical Working Group is discussed on chapter 10 (“Stakeholder Outreach and Engagement Process”).

As discussed in chapter 7 (“Types of IRPAs”), the OEB has also determined that the annual IRP report should include a summary of best available information on demand-side IRPAs.

The OEB also requires that the annual IRP report provide information on any efforts taken to explore the use of interruptible rates for meeting system needs, including how customers have been provided the opportunity to consider this option.

The OEB finds that the proposed timing for submission of the annual IRP report as part of the proceeding where Enbridge Gas proposes to clear the IRP Costs deferral accounts (which will be Enbridge Gas's Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application) is appropriate, because it will assist in the consideration of the costs recorded in the IRP Costs deferral accounts, and will be an efficient approach. The annual IRP report and the report from the IRP Technical Working Group (discussed in chapter 10 ("Stakeholder Outreach and Engagement Process")) are to be filed for information regardless of whether Enbridge Gas is seeking approval to clear any balances in the IRP Costs deferral accounts.

The OEB does not intend to approve the annual IRP report. Any decisions with respect to the annual IRP Report in the immediate proceeding in which it is filed would be related to findings on the disposition of amounts in the deferral accounts. The annual IRP report could inform OEB decisions in future proceedings, including approvals for IRP Plans, adjustments above 25% to approved IRP Plans, approvals for Leave to Construct projects, or future iterations of the IRP Framework.

The OEB finds the suggested introduction of metrics or a scorecard for IRP is premature. For a subsequent period, the Technical Working Group should recommend metrics for the OEB's consideration.

15 IRP COSTS DEFERRAL ACCOUNTS

Enbridge Gas requested approval of an IRP Costs deferral account which will track all incremental IRP-related costs not included in base rates (capital, operating and administrative costs) during the current deferred rebasing term, for the years 2021, 2022, and 2023.[88] Enbridge Gas submitted that the costs of assessing, planning, stakeholdering, procuring, implementing, and evaluating the performance of IRPAs and IRP pilot projects are incremental costs not included in Enbridge base rates during the current deferred rebasing term.[89]

Enbridge Gas indicated that both incremental administrative costs and project costs associated with a specific IRP Plan (including IRP pilot projects) could be tracked in the IRP Costs deferral account.

Incremental IRP administrative costs, as discussed in chapter 12 ("IRPA Cost Recovery and Accounting Principles"), would include costs to integrate IRP into Enbridge Gas's planning processes, complete the incremental stakeholdering, assess identified system constraints for IRPAs, and complete necessary IRP Monitoring and Reporting. Enbridge Gas estimated that it will need roughly 12 to 15 additional full-time equivalents for these tasks.

Project costs for IRP Plans could include the planning, implementing, administering, measuring, and verifying the effectiveness of specific investments in IRPAs, as well as ongoing operational and maintenance costs including the regular costs incurred to operate and maintain a specific IRPA investment after the project is in-service.

Enbridge Gas proposed to seek clearance of the IRP Costs deferral account on an annual basis as part of its Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application.

Enbridge Gas expects to be rebasing its rates for the 2024 year. Enbridge Gas indicated that the IRP Costs deferral account may still be needed beyond 2023 to track IRP program costs not included in base rates in 2024 and through the next deferred rebasing term.

No party opposed the establishment of an IRP Costs deferral account, but OEB staff and several other parties expressed some concern that not all IRP-related costs may be

[88] Argument-in-Chief, p. 15
[89] Argument-in-Chief, p. 44

incremental. OEB staff submitted that if IRP Plans are being developed as alternatives to facility projects that would have been implemented during the current deferred rebasing term, then IRP Plan project costs may not be incremental, as they may be replacing activities that were already funded through rates. IGUA submitted that the establishment of a deferral account should not guarantee or predetermine the nature or quantum of costs.

Findings

The OEB approves the establishment of two IRP Costs deferral accounts for the period from 2021 to 2023. The OEB is establishing an IRP Operating Costs Deferral Account for all IRP OM&A costs that will be considered operating expenses, and an IRP Capital Costs Deferral Account for IRP Plan project costs that will be eligible for recovery of capital-related revenue requirement impacts. The IRP Operating Costs Deferral Account for the OM&A costs should include incremental general administrative IRP costs, and incremental ongoing evaluation, operating and maintenance costs for specific approved IRP Plans. As noted in chapter 12 (“IRPA Cost Recovery and Accounting Principles”), these costs would also include enabling payments to service providers that are part of IRP Plans.

IRP Plan project costs where Enbridge Gas owns and operates the IRPA will be eligible for inclusion in rate base with an associated capital-related revenue requirement. These project costs should be recorded in a tracking account (the IRP Capital Costs Deferral Account) that will facilitate the calculation of the revenue requirement consistent with US GAAP for these project assets.

The OEB is not requiring sub-accounts for specific IRP Plans, at least at this time. However, in both IRP Costs deferral accounts, Enbridge Gas should track costs at a sufficiently detailed level or category to assist in a prudence review of the costs incurred, which would include tracking costs at the level of each approved IRP Plan separately. If Enbridge Gas believes that sub-accounts would be useful to facilitate the approach to rate class allocation and disposition, this can be addressed as part of the IRP Plan application.

Costs in the IRP Operating Costs Deferral Account for general IRP administrative costs, may be brought forward for disposition without any prior approval. Costs in this account related to specific projects (e.g. project operating and maintenance costs, enabling payments to competitive service providers) should not be brought forward for disposition until an IRP Plan has been approved. When an IRP Plan has been approved and the project is considered to be “in-service”, Enbridge Gas is also eligible to seek cost recovery of the project's capital-related revenue requirement through the IRP Capital Costs Deferral Account.

The balances brought forward for disposition in the IRP Costs deferral accounts should be based on actual expenditures. The balance for the IRP Capital Costs Deferral Account will include the revenue requirement impacts associated with project costs eligible for inclusion in rate base. The application to clear any balance in the IRP Capital Costs Deferral Account should describe the reasons for any variance between actual costs and the forecast costs that were included in an IRP Plan approval.

The OEB agrees with OEB staff that the prudence of recorded costs and the extent to which IRP costs are incremental to existing operations or projects funded by rates can be determined at the time of clearance of the IRP Costs deferral accounts. The clearance of this account will also address the approach to allocating IRP costs by rate class. For costs associated with specific IRP Plans, incrementality and rate class allocation will be addressed as part of the IRP Plan approval, with the prudence of actual costs to be addressed at the time of clearance.

The OEB concludes that allowing Enbridge Gas to request recovery of balances that are eligible for disposition in the two IRP Costs deferral accounts either on an annual basis or at rebasing is appropriate. The OEB agrees that Enbridge Gas's Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, which addresses disposition of the balances in a large number of deferral and variance accounts for Enbridge Gas on an annual basis, is an appropriate proceeding to address disposition of the balance in the IRP Costs deferral accounts.

The OEB directs Enbridge Gas to prepare a Draft Accounting Order for the two IRP Costs deferral accounts, consistent with the direction in this decision.

16 IRP PILOT PROJECTS

Enbridge Gas requested approval to develop and initiate two pilot projects by the end of 2022 – one of which will apply the new IRP Framework through development and implementation of an IRP Plan to meet an identified need/constraint (with an IRPA or combination of IRPAs to be determined) and the other of which will test a promising IRPA such as Demand Response, along with AMI, if possible.[90] Enbridge Gas indicated that the pilots would allow Enbridge Gas to test all or most of the components of the IRP proposal, from needs identification to binary screening to IRPA evaluation to project development and OEB approval to implementation and monitoring. Costs associated with pilot projects would be recorded in the proposed IRP Costs deferral account.[91]

Enbridge Gas indicated that it planned to engage with stakeholders and Indigenous groups before making a determination about what IRP pilot projects to pursue and also expected that the proposed Technical Working Group would provide input.

Enbridge Gas indicated that a reasonable timeline to identify, design, and deploy the IRP pilot projects would see initial steps beginning within three months of the issuance of the OEB's IRP Framework, with deployment by the end of 2022.

Enbridge Gas indicated that it would likely seek approval from the OEB for its proposed IRP pilot projects through IRP Plan applications.[92]

Enbridge Gas submitted that it may be appropriate to wait until information is gained through these pilot projects before proceeding to implement further IRP Plans.

As part of its evidence, Enbridge Gas also filed a report on a pilot project in Ingleside, Ontario, that assessed the impacts and costs of using geotargeted DSM to reduce peak demand, and tested the use of automated meter reading technology to collect and evaluate hourly demand data.[93]

There was widespread support and agreement by stakeholders that pilot projects would be an important and necessary component of the IRP Framework. In addition, evidence

[90] Argument-in-Chief, p. 15
[91] Enbridge Gas also proposed that some of the funding for IRP pilot projects could potentially come from the balance in the Tax Variance Deferral Account. However, in its decision on the disposition of that account balance, the OEB denied that proposal. EB-2020-0134, Decision and Order, May 6, 2021, p. 11
[92] Argument-in-Chief, p. 40
[93] Enbridge Gas Reply Argument, Exhibit C, Appendix A, filed December 11, 2020

filed by all expert witnesses indicated that pilot projects had played an important role for other jurisdictions pursuing IRP (in the natural gas and electricity sectors).

Several parties provided suggestions as to how to improve learnings from the pilots. EFG's expert testimony (supported by ED and GEC) was that both Enbridge Gas's previous and proposed new pilots were too narrow, and a broader approach should be used to maximize learnings about IRP. EFG recommended that Enbridge Gas pursue multiple approaches (utility-run and procurement-driven) and multiple types of IRPAs.[94] OEB staff encouraged Enbridge Gas to consider EFG's suggestions, and also supported Enbridge Gas's comments that any future IRP pilot project should be sited in an area that includes a broader diversity of customer types and complexities so as to better test deployment. LIEN and VECC requested that Enbridge Gas situate IRP pilot projects in areas that include diverse customer types (including low-income customers).

In reply, Enbridge Gas indicated that it will be important to situate IRP pilot projects in areas that are representative of its service territory, taking into account where future system constraints are likely to be encountered. OSEA requested that the OEB consider requiring Enbridge Gas to prepare a summary report on Enbridge Gas's ongoing review of demand response pilot projects in other jurisdictions. Pollution Probe recommended one pilot based on targeted DSM, and one based on an alternative energy technology, with pilots to be undertaken in alignment with willing municipalities.

OEB staff submitted that the nature and details of the IRP pilot projects should be determined following consultation with stakeholders and the IRP Technical Working Group. OEB staff proposed that an application for approval of the IRP pilot projects be filed within 12 months of the issuance of the IRP Framework. In reply, Enbridge Gas indicated that it would aim to meet this proposed timeline, but was not able to commit, given uncertainties.

OEB staff did not support Enbridge Gas's proposal that it needs to wait for results from pilot projects before developing other IRP Plans, if Enbridge Gas determines that an IRP Plan is the best approach to meeting a system need with technologies and/or resources it is already familiar with, such as DSM.

SEC supported pilot projects and indicated that the pilots would inform Enbridge Gas's further consideration of IRP within its rebasing application. As a corollary, SEC submitted that the OEB should establish a moratorium on new facility projects between

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[94] Presentation to the OEB, Energy Futures Group, Presentation Day, February 19, 2021, pp. 29-30

now and rebasing, with the only exception being projects that Enbridge Gas can demonstrate are too urgent to wait for the rebasing application, and are not reasonably likely to be affected by IRP analysis.

In reply, Enbridge Gas clarified that it would identify and develop IRP Plans, but that it was too early to decide whether it would proceed to implementation, pending pilot results. Enbridge Gas disagreed with the moratorium on new facility projects proposed by SEC, stating that this would create a backlog in addressing constraints.

Findings

The OEB notes that there was universal support for Enbridge Gas's proposal to develop and implement two IRP pilot projects, and the OEB agrees with this approach. The pilots were seen as an effective approach to understand and evaluate how IRP can be implemented to avoid, delay or reduce facility projects. The use of pilot projects to better understand the development of IRP and IRPAs was generally used in other jurisdictions.

The OEB expects that the IRP pilot projects will be selected and deployed by the end of 2022 as proposed by Enbridge Gas. The detailed consideration of IRP pilot projects should commence shortly after the issuance of the IRP Framework with input being sought from the IRP Technical Working Group described in chapter 10 ("Stakeholder Outreach and Engagement Process").

The OEB finds that it is unnecessary for this decision to provide detailed direction on the pilot projects and recommends that the nature of the pilots should be responsive to the opportunities that arise. Enbridge Gas should then apply to the OEB for approval of the IRP pilot projects providing the information and following the approach described in the chapter 13 ("Future IRP Plan Applications").

While the OEB understands Enbridge Gas's reasoning behind waiting for the conclusion of the pilot projects before developing other IRP Plans, this should not be a barrier to addressing a system need through a non-pilot IRP Plan, if an exceptional time-limited opportunity arises prior to the completion of the pilots. The OEB does not agree with SEC that Enbridge Gas should defer all infrastructure builds until rebasing, when information from the pilots is available. The OEB shares Enbridge Gas's concern that this could create a backlog in addressing any constraints. The OEB also notes that the government of Ontario's policy concerning expansion of natural gas infrastructure to communities currently unserved by natural gas supports the ongoing construction of infrastructure builds in those communities.

Enbridge Gas should share key learnings from the pilots by reporting to the OEB and stakeholders through the annual IRP report, and more frequent updates to the IRP Technical Working Group, as needed. This experience will facilitate the development of other IRP Plans and identify areas for enhancement to the IRP Framework.

The IRP pilot project costs are to be tracked in the IRP Costs deferral accounts, and recovery can be requested annually for prudently incurred costs.

Enbridge Gas is encouraged to use the IRP pilot projects as a testing ground for an enhanced DCF+ test as discussed in section 8.3 (“Two-Stage Evaluation Process”).

17 AMI ACKNOWLEDGEMENT

Enbridge Gas requested that the IRP Framework include an indication of the OEB's support for the role of Advanced Metering Infrastructure (AMI) as an important enabler of successful IRP and IRPAs.[95] As defined by Enbridge Gas, AMI is an integrated system of meters, end points, communications networks, and data management systems that enables two-way communication between utilities and customer meters. AMI would enable more frequent data collection of actual gas consumption at the customer level (e.g., hourly data instead of monthly).

Enbridge Gas indicated that AMI will allow for the collection of the hourly data that it requires to not only target IRPAs effectively but also to monitor and verify their effectiveness to ensure that the IRPAs are performing as expected and to ensure peak period demand reductions are materializing. Without AMI, Enbridge Gas indicated that it will need to rely on system modelling to assess IRPAs, which will drive the need to overbuild the IRPA, as well as robust additional evaluation, measurement, and verification work, both of which drive up costs for IRPA(s).[96]

Enbridge Gas did not request approval for AMI funding within this proceeding but indicated that it is considering requesting broad deployment of AMI in the future in a separate proceeding, likely its 2024 rebasing application.[97] Enbridge Gas also indicated that it may request approval to target key geographic areas for AMI deployment where future constraints are identified and where AMI might be useful in evaluating IRPAs' effectiveness.

Most parties (with the exception of OSEA) did not support Enbridge Gas's request that AMI be noted as an important enabler of IRP, although several acknowledged that AMI could provide information that would be valuable in IRP implementation.

Parties submitted that Enbridge Gas had not provided sufficient evidence or a compelling business case for AMI and expressed concerns that an endorsement of AMI would be premature, particularly if it influenced specific AMI-related funding requests which Enbridge Gas might make to the OEB in the future.

Parties also noted that other monitoring solutions, such as metering at strategic points in the distribution system, may be preferable or more cost-effective than metering at the

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95 Argument-in-Chief, p. 15
96 Exhibit B, pp. 35-36. See also Exhibit I.Staff.4(f)
97 Argument-in-Chief, pp. 47-49

level of individual customers, depending on the specifics of an IRP Plan. OEB staff submitted that the expected benefits of monitoring and metering technologies to enable more effective consideration, implementation, and evaluation of IRPAs in meeting system needs should be considered along with their costs.

Several parties commented that pilot projects could be used to assess the value of AMI, which could include an approach comparing IRP with and without AMI.

Findings

The OEB concludes that there is insufficient information to determine if AMI is a cost-effective enabler of IRP and IRPAs such as demand response. Using the more conservative derating factors (or IRPA oversubscription) that Enbridge Gas proposed during this early stage of IRP might be a more efficient way to gain experience and ensure that peak period demand reductions are achieved. Metering at strategic points in the distribution system, as suggested by several parties, might also be worth exploration. Enbridge Gas can provide a business case with additional rationale for AMI, either as part of a specific IRP Plan application, or as part of its next rebasing application.

18 IMPLEMENTATION

A final “Integrated Resource Planning Framework for Enbridge Gas” is attached as Appendix A to this Decision and Order. The Framework is a companion document to this Decision and Order regarding IRP for Enbridge Gas. Enbridge Gas is expected to begin integrating IRP into its existing planning processes, in a manner consistent with the IRP Framework, effective immediately.

Specific milestones for Enbridge Gas in the IRP Framework include:

- Filing an annual IRP report as part of its Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application
- Filing its first version of the Asset Management Plan reflecting the updated IRP Assessment Process in Fall 2022
- Selecting and deploying IRP pilot projects by the end of 2022
- As part of its next rebasing application, filing a study on interruptible rates to determine how they might be modified to increase customer adoption of this alternative service in order to help reduce peak demand
- As part of its next rebasing application, filing an analysis of the historical accuracy of Enbridge Gas’s demand forecast, as required by section 2.3.2 of the Filing Requirements for Natural Gas Rate Applications

In addition, OEB staff shall establish the IRP Technical Working Group, including a terms of reference and the initial selection of Technical Working Group members, by the end of 2021. The OEB expects that the first priorities of the Technical Working Group will be the IRP pilot projects, and enhancements or additional guidance in applying the DCF+ evaluation methodology in the context of IRP.

Enbridge Gas shall file a draft accounting order for the establishment of the IRP Operating Costs Deferral Account, and IRP Capital Costs Deferral Account as described in chapter 15 (“IRP Costs Deferral Accounts”).

The OEB has also scheduled a process for intervenor costs.

19 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The guidance provided in this Decision and Order, including the document "Integrated Resource Planning Framework for Enbridge Gas" in Appendix A, is effective immediately.

2. Enbridge Gas Inc. shall file a draft accounting order for the IRP Costs deferral accounts consistent with this Decision and Order by **August 12, 2021**.

3. OEB staff and intervenors may file any comments on the draft accounting order by no later than **August 26, 2021**. No cost awards will be granted for this procedural step.

4. Intervenors shall file with the OEB, and forward to Enbridge Gas Inc., their respective cost claims by **August 26, 2021**.

5. Enbridge Gas Inc. shall file with the OEB, and forward to intervenors, any objections to the claimed costs by **September 9, 2021**.

6. Intervenors shall file with the OEB, and forward to Enbridge Gas Inc., any responses to any objections for cost claims by **September 16, 2021**.

7. Enbridge Gas Inc. shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

Parties are responsible for ensuring that any documents they file with the OEB, such as applicant and intervenor evidence, interrogatories and responses to interrogatories or any other type of document, **do not include personal information** (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

Please quote file number, **EB-2020-0091** for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the OEB's online filing portal.

- Filings should clearly state the sender's name, postal address, telephone number and e-mail address
- Please use the document naming conventions and document submission standards outlined in the Regulatory Electronic Submission System (RESS) Document Guidelines found at the Filing Systems page on the OEB's website
- Parties are encouraged to use RESS. Those who have not yet set up an account, or require assistance using the online filing portal can contact registrar@oeb.ca for assistance

All communications should be directed to the attention of the Registrar at the address below and be received by end of business, 4:45 p.m., on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Michael Parkes at michael.parkes@oeb.ca and OEB Counsel, Michael Millar at michael.millar@oeb.ca.

Email: registrar@oeb.ca

Tel: 1-877-632-2727 (Toll free)

DATED at Toronto July 22, 2021

ONTARIO ENERGY BOARD

Original Signed By

Christine E. Long
Registrar

Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

July 22, 2021

Integrated Resource Planning Framework for Enbridge Gas

EB-2020-0091 (Appendix A)

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Ontario

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1 INTRODUCTION AND PURPOSE

This document describes the first-generation Integrated Resource Planning (IRP) Framework for Enbridge Gas. Within the energy sector generally, integrated resource planning usually refers to a planning process that evaluates and compares both supply-side and demand-side options to meeting an energy system need, and may also refer to consideration of multiple energy sources, and co-ordination or integration between multiple energy service providers. A definition of IRP specific to Enbridge Gas's operations is provided in chapter 2 ("Definitions").

This IRP Framework is a companion document to the OEB's July 22, 2021 Decision and Order on Enbridge Gas's Integrated Resource Planning proposal (EB-2020-0091), regarding IRP for Enbridge Gas. While the IRP Framework is intended to be fully consistent with the Decision and Order, in case of any discrepancy, the wording in the Decision and Order will prevail. The expectation is that enhancements and improvements will be made in the future on the basis of the experience gained in Ontario with pilot projects and other IRP activities, drawing on successes achieved in other jurisdictions, and future policy direction.

The IRP Framework provides direction to Enbridge Gas on topics to be covered in an IRP Plan (defined in chapter 2 ("Definitions")), and the OEB's requirements as Enbridge Gas considers IRP to meet its system needs. If Enbridge Gas has reasons for a specific IRP Plan to deviate from the IRP Framework, it should justify why deviations from the Framework requirements are appropriate.

The IRP Framework has been established for Enbridge Gas; however, it should also be used as a resource to guide EPCOR Natural Gas Limited Partnership when it examines infrastructure investments and potential alternatives.

2 DEFINITIONS

The following terms are defined in the IRP Framework:

- **Integrated Resource Planning:** A planning strategy and process that considers Facility Alternatives and IRP Alternatives (including the interplay of these options) to address the system needs of Enbridge Gas's regulated operations, and identifies and implements the alternative (or combination of alternatives) that is in the best interest of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management.

- **IRP Assessment Process:** The process used by Enbridge Gas to determine the preferred solution to meet specific system needs, including consideration of Facility Alternatives and IRP Alternatives.

- **Facility Alternative:** A potential infrastructure solution considered under the IRP Assessment Process in response to a specific system need of Enbridge Gas. In this IRP Framework, the term is synonymous with a traditional or conventional facility project. This would typically include a hydrocarbon line (as defined in the *OEB Act*) developed by Enbridge Gas, and ancillary infrastructure. Facility Alternatives determined by Enbridge Gas to be the preferred solution to meet the system need will often require approval from the OEB through a Leave to Construct application. For clarity, non-traditional solutions to system needs that include infrastructure developed by Enbridge Gas, such as injection of compressed or renewable natural gas, or storage of natural gas within the distribution or transmission system, are considered to be IRP Alternatives and not Facility Alternatives.

- **IRP Alternative (IRPA):** A potential solution other than a Facility Alternative considered in Enbridge Gas's IRP Assessment Process in response to a specific system need of Enbridge Gas. IRPAs determined by Enbridge Gas to be the preferred solution to meet the system need (alone, in combination with other IRPAs, or in combination with a Facility Alternative) would likely be brought forward for approval from the OEB through an IRP Plan.

- **IRP Plan:** A plan filed by Enbridge Gas for OEB approval in response to a specific system need, that includes one or more IRPAs.

3 GUIDING PRINCIPLES

The OEB has adopted the following guiding principles for IRP. IRP Plans filed with the OEB should include a section to discuss how these guiding principles have been addressed.

- Reliability and safety – In considering IRPAs as part of system planning processes, Enbridge Gas's system design principles cannot be compromised, and the reliable and safe delivery of firm contracted peak period natural gas volumes to Enbridge Gas's customers must remain of paramount importance.
- Cost-effectiveness – IRPAs must be cost-effective (competitive) compared to Facility Alternatives and other IRPAs, including taking into account impacts on Enbridge Gas customers.
- Public policy – IRP will be considered in a manner to ensure that it is supportive of and aligned with public policy, and in particular the OEB's statutory objectives for the natural gas sector.
- Optimized scoping – Recognizing that reviewing IRPAs for every forecast infrastructure project would be extremely time intensive, binary screening should be undertaken, to confirm which forecast need(s) should undergo evaluation of IRPAs, and to ensure a focus at the outset on efficient and effective IRPA investment.
- Risk management – Economic risks associated with both Facility Alternatives and IRPAs in meeting system needs are evaluated and appropriately mitigated. Risks and rewards are allocated appropriately between Enbridge Gas and its customers.

4 TYPES OF IRPAS

Demand-side programming may include IRPAs such as geotargeted energy efficiency programs, and demand response programs (which incent or oblige the customer to reduce or shift energy usage during peak periods). Demand-side IRPAs are expected to target specific constrained areas and (amongst other things) encourage customers to reduce peak consumption.

Interruptible rates can also be used to reduce peak demand. While approval of interruptible rates would be considered in a rebasing rate application, the impact of interruptible rates to meet a system need/constraint should be considered in an IRP Plan in combination with demand-side or supply-side alternatives.

Supply-side IRPAs could include injection of compressed natural gas into the pipeline system in a constrained area, or renewable natural gas sourced within the constrained area. Supply-side IRPAs may also include market-based supply side alternatives. This could include contractual arrangements requiring delivery of natural gas to specific points on Enbridge Gas's system that harness the capability of existing pipeline infrastructure (including non-Enbridge Gas pipelines) to avoid or defer the need for Enbridge Gas to build new pipeline infrastructure.

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. Enbridge Gas can seek opportunities to work with the Independent Electricity System Operator or local electricity distributors to facilitate electricity-based energy solutions to address a system need/constraint, as an alternative to IRPAs or facility projects undertaken by Enbridge Gas. The OEB is not establishing this as a requirement.

For both demand-side and supply-side IRPAs, Enbridge Gas should look to procure equipment or activities through the competitive market, where feasible and cost-effective.

Enbridge Gas should consider both combination IRP Plans (that may include multiple supply-side or demand-side IRPAs or an IRPA in combination with a Facility Alternative) and bridging solutions in its IRP assessment process if the bridging solution provides the best alternative in the near term, while exploring longer term solutions.

To support the analysis of IRPAs and promote more timely development of IRP Plans, Enbridge Gas shall provide a document on best available information for demand-side

IRPAs. This will be provided with Enbridge Gas's annual IRP report discussed in chapter 10 ("Monitoring and Reporting").

5 IRP ASSESSMENT PROCESS

Enbridge Gas will use a four-step IRP Assessment Process to determine the best approach to meeting system needs, including whether to pursue IRPAs for an identified need/constraint. In a project-specific application (Leave to Construct or IRP Plan), Enbridge Gas is required to demonstrate that it has followed this process including the results of the analysis at each stage of the process.

1. Identification of Constraints

2. Binary Screening Criteria

3. Two-Stage Evaluation Process

4. Periodic Review

The OEB expects that Enbridge will integrate its IRP Assessment Process into its annual planning.

Within its annual IRP report, Enbridge Gas shall report on the results of its IRP Assessment Process, including reporting on those system needs where a negative result at step two (binary screening) or step three (technical/economic evaluation) resulted in a determination by Enbridge Gas for no further assessment of IRPAs.

5.1 IRP Assessment Process Step 1: Identification of Constraints

Enbridge Gas shall identify potential system needs/constraints up to ten years in the future, and describe these in annual updates to the Asset Management Plan (AMP) to allow time for a detailed examination of IRPAs. The AMP is currently filed each year as part of Enbridge Gas's rate adjustment proceedings. The AMP process addresses all utility assets within Enbridge Gas's regulated operations.

An updated version of the AMP will be filed each year. The information filed within each AMP should include:

- a list of identified system needs
- the status of IRP Plan consideration for each system need
- the result of the initial binary screening
- details as to whether and why IRP Plans have been screened out at subsequent steps, with supporting rationale

- any material changes to the demand forecast, relative to the demand forecast that was assessed as part of the last rebasing application

The OEB expects that, for projects brought to the OEB for approval (both Leave to Construct projects and IRP Plans), the system need will have previously been identified in the AMP (although the preferred project to meet the system need may not have been determined at that time). For any previously unidentified needs, Enbridge Gas will need to provide an explanation as to why the project is needed at this time.

5.2 IRP Assessment Process Step 2: Binary Screening Criteria

The IRP Framework will include screening criteria, in order to focus on those situations where there is a reasonable expectation that an IRPA could efficiently and economically meet the system need.

Enbridge Gas will apply these binary screening criteria to identified system needs/constraints (as identified in step 1) to determine whether further IRP evaluation is appropriate. Binary screening would thus exclude some system needs from further IRP consideration. System needs where IRP is not screened out through this binary screening would next move to the two-stage IRP evaluation process.

The OEB has established the following screening criteria for the first-generation IRP Framework.

<u>Emergent Safety Issues</u>

The first criterion deals with urgent or imminent issues. The safety and reliability of the gas system is paramount. Removing constraints that jeopardize this system performance does not allow time for the development and assessment of an IRP Plan.

i. ***Emergent Safety Issues*** *– If an identified system constraint/need is determined to require a facility project for Enbridge Gas to offer safe and reliable service or to meet an applicable law, an IRP evaluation is not required. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and needed to be replaced as quickly as possible to ensure the safety of local communities and Enbridge Gas's broader transmission and distribution systems. Longer-term safety related system constraints/needs may be appropriate for an IRP Plan and should be considered on a case-by-case basis.*

Timing

It takes time to assess and implement an IRP Plan along with demonstration that the constraint is being mitigated. Once a ten-year AMP consistent with the IRP Framework has been in place for several years, there should be fewer situations where a timing criterion is needed; however, for this first-generation IRP Framework, the OEB is establishing a timing criterion. The use of supply-side options might be possible to meet an identified need within a shorter period.

ii. ***Timing*** *– If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.*

Customer-Specific Builds

Where the customer fully pays for the incremental infrastructure costs associated with a facility project, in the form of a Contribution in Aid of Construction, consideration of an IRP Plan is not required.[1] However, Enbridge Gas is encouraged to discuss demand-side management (DSM) opportunities with customers to potentially reduce the size of the build.

iii. ***Customer-Specific Builds*** *– If an identified system need has been underpinned by a specific customer's (or group of customers') clear request for a facility project and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required.*

Community Expansion & Economic Development

Given the goal of the Ontario Government's Access to Natural Gas legislation[2] to extend gas service to designated communities, Enbridge Gas is not required to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need. However, Enbridge Gas is encouraged to discuss DSM opportunities with customers to potentially reduce the size of the build.

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[1] The incremental costs recovered through a Contribution in Aid of Construction are set at an amount that reduces the capital cost of a project for Enbridge Gas ratepayers such that the project becomes economically feasible, which generally requires a profitability index greater than or equal to one.
[2] *Access to Natural Gas Act, 2018*, S.O. 2018, c. 15 - Bill 32

iv. ***Community Expansion & Economic Development*** *– If a facility project has been driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities, then an IRP evaluation is not required.*

Pipeline Replacement and Relocation Projects

A minimum cost of the facility project that would be built to meet a system need (in the absence of IRP) is required to justify the time and effort to conduct an IRP evaluation and potentially develop an IRP Plan. Projects under $2 million should be screened out unless the government makes regulatory changes establishing a $10 million threshold for OEB Leave to Construct approvals, in which case, the criteria should use $10 million to determine if an IRP evaluation is appropriate.

v. ***Pipeline Replacement and Relocation Projects*** *– If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than the minimum project cost that would necessitate a Leave to Construct approval, then an IRP evaluation is not required.*

5.3 IRP Assessment Process Step 3: Two-Stage Evaluation Process

For system needs progressing past the initial IRP binary screening, Enbridge Gas will determine whether to proceed with an IRP Plan through a two-stage evaluation. First, Enbridge Gas will determine whether potential IRPAs could meet the identified constraint/need. If yes, then Enbridge Gas will compare one or more IRP Plans to the baseline Facility Alternative, using a Discounted Cash Flow-plus (DCF+) economic test, to determine the optimum solution to meet the system need. It is expected that the two-stage evaluation process would commence sufficiently far in advance of the date that the constraint/need must be met in order to allow for time for an IRP Plan to be developed, approved, implemented and monitored for effectiveness in advance of the date when a facility project would be required.

Stage 1: Technical Evaluation

The first stage will look at the technical viability of potential IRPAs to reduce peak demand to the degree required to meet the identified system need, using best available information (including information on IRPAs from Enbridge Gas's annual IRP report), to determine whether an IRP Plan including one or more IRPAs would be a viable option. Enbridge Gas may use derating factors (i.e., assuming less than 100% of the forecast peak demand reduction from the IRPAs would be delivered) or oversubscription of IRPAs to address uncertainty regarding forecast savings. These derating factors may be relevant to both the technical and economic evaluations. In any subsequent application for OEB approval of specific IRP Plans, Enbridge Gas should identify both the level of oversubscription and the supporting rationale.

Stage 2: Economic Evaluation

The economic evaluation used to compare the IRP Plan(s) to the baseline Facility Alternative will consist of a three-phase DCF+ evaluation, including a focus on rate impacts, as identified in phase 1 of the DCF+ test.

The DCF+ test will be based on the three-phase economic test that Enbridge Gas is required to use to assess the costs and benefits of potential transmission system expansions, under the parameters established by the *Report of the Board on the Expansion of the Natural Gas System in Ontario* (the E.B.O. 134 report). The principles of this test are summarized in the OEB's *Filing Guidelines on the Economic Tests for Transmission Pipeline Applications*. In the IRP Framework, the DCF+ test will include the following phases:

- Phase 1 assesses the economic benefits and costs from the utility perspective, and indicates whether the project is likely to result in future increases to utility rates.
- Phase 2 assesses the incremental economic benefits and costs incurred by customers from the IRP Plan(s) or Facility Alternative(s).
- Phase 3 assesses the incremental societal benefits and costs.

A Net Present Value will be calculated for each phase. Results from each phase will be presented separately for transparency, but will also be summed together.

The DCF+ results for the IRP Plan(s) and the baseline Facility Alternative will be compared to one another to determine which alternative is optimal. IRP Plans that included some combination of IRPA and facility project can also be tested using this approach.

Enbridge Gas has some discretion to select an alternative to meet a system need that does not have the highest score on phase 1 of the DCF+ test, as there may be considerations or factors that are important in phases 2 or 3, or are difficult to quantify. However, this will require justification if Enbridge Gas recommends a higher cost alternative.

The OEB accepts the categories of benefits and costs proposed by Enbridge Gas for the three phases of the DCF+ test (shown in Table 1) for the use of this test in the IRP Framework.

Table 1: Discounted Cash Flow-Plus Test Costs and Benefits

Benefit/Cost	Phase 1	Phase 2	Phase 3
Benefits			
Incremental Revenues	x		
Avoided Utility Infrastructure Costs [2]	x		
Avoided Customer Infrastructure Costs [3]		x	
Avoided Utility Commodity/Fuel Costs [4]	x		
Avoided Customer Commodity/Fuel Costs [5]		x	
Avoided Operations & Maintenance	x		
Avoided Greenhouse Gas Emissions		x	
Other External Non-Energy Benefits			x
Costs			
Incremental Capital Expenditure [1]	x		
Incremental Operations & Maintenance [1]	x		
Incremental Taxes	x		
Incremental Utility Commodity/Fuel Costs [4]	x		
Incremental Customer Commodity/Fuel Costs [5]		x	
Incremental Greenhouse Gas Emissions		x	
Incremental Customer Costs		x	
Other External Non-Energy Costs			x

Notes:
(1) Capital and Operations & Maintenance is inclusive of program administrative costs
(2) Avoided or reduced infrastructure capital costs of the utility (e.g., smaller diameter pipe)
(3) Avoided or reduced infrastructure capital costs of the customer (e.g., reduced Contribution in Aid of Construction)
(4) Avoided or incremental fuel costs of the utility (e.g., compressor fuel and unaccounted for gas)
(5) Avoided or incremental fuel costs of the customer (e.g., lower/higher natural gas use, lower/higher electricity use)

Further work will be needed to refine the use of the DCF+ test in the context of IRP. The DCF+ test could be improved to better list and define the costs and benefits of Facility Alternatives and IRPAs, and clarify how these costs and benefits should be considered within the DCF+ test. This could include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. Enbridge Gas shall study improvements to the DCF+ test for IRP, and is encouraged to consult with the IRP Technical Working Group and to use the IRP pilot projects as a testing ground for an enhanced DCF+ test. In particular, the IRP Technical Working Group should consider how different carbon pricing scenarios should be used in the DCF+ calculation. The OEB directs that Enbridge Gas file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.

5.4 IRP Assessment Process Step 4: Periodic Review

Material changes may occur that could impact Enbridge Gas's determination as to how best to meet a system need. These may include changes occurring when implementing an IRP Plan after receiving project approval. Examples could include where the nature or timing of an identified need/constraint alters materially, or significant policy changes are announced by government or the OEB. In such cases, Enbridge Gas may review its IRP determinations, and may choose to discuss with the IRP Technical Working Group.

Updates of this nature should be provided by Enbridge Gas as part of its annual IRP report. If Enbridge Gas plans to increase its spending on an approved IRP Plan by more than 25%, it will need to request OEB approval for the change, as discussed in chapter 9 ("Future IRP Plan Applications").

6 STAKEHOLDER OUTREACH AND ENGAGEMENT PROCESS

6.1 Stakeholder Engagement Process

Enbridge Gas is required to use a three-component stakeholder engagement process to provide input into its IRP activities.

The three components will involve:

1. Gathering of Stakeholder Engagement Data and Insight: Seeking insights from stakeholders and various market participants by working within existing stakeholder engagement channels, on an ongoing basis, to mitigate incremental expenses and leverage existing relationships.
2. Stakeholder Days: Annual regional stakeholder events focused on IRP to discuss plans and progress with IRP, including specific discussion of needs/constraints identified in the AMP and the plans to address such items through IRP. These would be held on an annual basis shortly after Enbridge Gas files its AMP update within Phase 2 of the annual rates proceeding.
3. Targeted Engagement: Project-specific consultation dealing with specific IRPAs or IRP Plans (identified for a specific need in a specific geographic region), with stakeholders from the specific geographic area relevant to the IRPA. Project-specific consultation must be done in advance of seeking project approval from the OEB.

It is expected that Enbridge Gas will record comments from stakeholders and Indigenous groups participating in components 2 and 3 and the responses from Enbridge Gas to these comments. This information is to be filed in any subsequent IRP Plan/Leave to Construct application. Chapter 7 (“Indigenous Engagement and Consultation”) provides additional details on Indigenous engagement and consultation.

Enbridge Gas shall also establish a website to facilitate the broad sharing of information on IRP stakeholdering efforts.

6.2 Technical Working Group

In addition to the three-component stakeholder process, the OEB is establishing an IRP Technical Working Group led by OEB staff, similar to the Demand-Side Management Evaluation Advisory Committee. OEB staff will establish a terms of reference and select the membership. Establishment of the IRP Technical Working Group, including a terms of reference, and the initial selection of working group members, shall be done by the end of 2021.

The IRP Technical Working Group has an objective of providing input on IRP issues that is of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework.

The OEB expects that the first priorities of the IRP Technical Working Group will be:

- Consideration and implementation of IRP pilot projects
- Enhancements or additional guidance in applying the DCF+ evaluation methodology

Additional topics to be examined by the IRP Technical Working Group could include:

- Learnings from IRPAs and IRP implementation in other jurisdictions
- Developing IRP performance metrics for the OEB's consideration
- Treatment of stranded assets in other jurisdictions

The IRP Technical Working Group will also be expected to review a draft of Enbridge Gas's annual IRP report, with the review coordinated by OEB staff. Enbridge Gas should provide a draft of the annual IRP report to the IRP Technical Working Group far enough in advance of its planned filling to the OEB to allow the Technical Working Group time to review and comment. A report from the Technical Working Group to the OEB should be filed by OEB staff in the same proceeding in which Enbridge Gas's annual IRP report is filed. The Technical Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Technical Working Group, and may also describe other activities undertaken by the Technical Working Group in the previous year.

As the natural gas system operator, Enbridge Gas retains the sole responsibility to make final system planning decisions and to advance IRP Plans and/or Leave to Construct applications. While Enbridge Gas is expected to consider any input provided by the IRP Technical Working Group, the IRP Technical Working Group will not have "voting rights" that bind Enbridge Gas with regards to its system planning decisions.

7 INDIGENOUS ENGAGEMENT AND CONSULTATION

Enbridge Gas will make efforts to accommodate participation of Indigenous groups within its stakeholder engagement process and work with these groups as appropriate to address any concerns. The OEB endorses this approach and expects that Indigenous engagement will take place in cases where material Indigenous interests are engaged.

In addition to any broader stakeholder engagement with Indigenous groups, Enbridge Gas is required to conduct consultation with respect to any potential impacts to Aboriginal or treaty rights in relation to proposed IRP Plans (which may include the individual IRPAs considered) and Leave to Construct applications. Any concerns can be considered on a case-by-case basis when an IRP Plan or Leave to Construct application comes before the OEB for approval.

When Enbridge Gas requests approval for an IRP Plan or a Leave to Construct, it will be necessary for Enbridge Gas to follow the requirements in the *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario*[3] regarding Indigenous consultation, if applicable.

[3] Ontario Energy Board, Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 2016

8 IRPA COST RECOVERY AND ACCOUNTING TREATMENT PRINCIPLES

Costs for Enbridge Gas associated with IRP implementation fall into three categories:

- Incremental IRP administrative costs required to meet the increased workload related to IRP, including integrating IRP into Enbridge Gas's planning processes, completing the incremental stakeholdering, assessing identified system constraints for IRPA(s), and completing necessary IRP monitoring and reporting.
- IRPA Project costs including the planning, implementing, administering, measuring and verifying the effectiveness of specific investments in IRPAs.
- Ongoing operational and maintenance costs including the regular costs incurred to operate and maintain a specific IRPA investment after the project is in-service.

IRPA project costs, similar to the costs for infrastructure builds, will be eligible for inclusion in rate base where Enbridge Gas owns and operates the IRPA. Enbridge Gas should include 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. Until rebasing, the associated revenue requirement of these project costs will be recorded in a capital costs deferral account for recovery annually or at rebasing as requested by Enbridge Gas.

Where Enbridge Gas proposes to make an enabling payment to a competitive service provider and does not own or operate the asset, these costs, if approved, will be included in the category of ongoing operational and maintenance costs and recovered as operating expenses. The OEB requires that Enbridge Gas select the most efficient and cost-effective option for its customers, between Enbridge Gas ownership and third-party ownership with an enabling payment. Until rebasing, these operating costs will be recorded in an operating costs deferral account for recovery annually or at rebasing as requested by Enbridge Gas. Incremental IRP administrative costs and other ongoing operational and maintenance costs will also be treated as expenses and recorded in this account.

The IRPA project costs eligible for inclusion in rate base will attract the same cost of capital as other rate based assets for Enbridge Gas. The depreciation period for the IRPA assets will align with the expected useful life of the asset, which will likely be the time over which the underlying IRPA is expected to provide peak load reduction.

Details about how these principles will be applied to specific IRPAs and IRP Plans will be determined in the IRP Plan applications. As part of an IRP Plan application, Enbridge Gas should provide details on which IRP Plan costs it believes are eligible for inclusion in rate base, versus those that should be considered operating expenses, with supporting rationale.

9 FUTURE IRP PLAN APPLICATIONS

When Enbridge Gas determines that an IRPA (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. The IRP Framework establishes a new approval process for IRP Plans, under section 36 of the OEB Act.

An IRP Plan approval from the OEB will operate as an endorsement of the IRP Plan, and approve the cost consequences. The costs would then be recovered, subject to a prudence review, through the IRP Costs deferral accounts annually and/or at Enbridge Gas's next rebasing application.

An IRP Plan approval will be mandatory if the forecast costs of the IRP Plan exceed the minimum project cost that would necessitate a Leave to Construct approval for a pipeline project (currently $2 million, proposed to increase to $10 million).

An IRP Plan application should include information similar to what is found in a Leave to Construct application, including:

- Purpose of the IRP Plan
- How the IRP Framework's guiding principles have been addressed
- Information on system need (forecast need/constraint being addressed)
- Discussion of alternatives (why the IRP Plan was selected, including the results of the economic evaluation)
- Description of the IRP Plan and IRPAs, including forecast impacts, costs, and implementation timing)
- Proposed approach to evaluation and monitoring
    - This could include a business case for any proposals for advanced metering infrastructure if this has not been assessed in Enbridge Gas's rebasing application
- Proposed approach to cost recovery (including details on costs Enbridge Gas proposes for inclusion in rate base, versus those that should be considered operating expenses, together with a supporting rationale)
    - Enbridge Gas should identify whether it intends to seek recovery of all or part of the IRP Plan costs, including rationale as to why these costs are incremental to activities included in existing rates
- Proposed approach to cost allocation (using the facility project that is being avoided, deferred, or reduced by the IRP Plan as a reference for the approach to cost allocation, as appropriate)

- In-service date, and any considerations that may apply regarding when the IRP Plan should be considered to be in-service such that Enbridge Gas is eligible for cost recovery
- Expected bill impacts
- Land and environmental issues (where relevant)
- A record of stakeholder engagement and Indigenous engagement and consultation (as appropriate)
- Conditions of approval

Prudently incurred costs associated with an approved IRP Plan will be eligible for cost recovery.

Enbridge Gas should seek approval for an adjustment to an IRP Plan, should the cost adjustment be an increase of greater than 25% of the approved cost. When seeking recovery of actual IRP Plan costs, Enbridge Gas will need to demonstrate that it has been prudent in managing its actions and resulting costs, as is typical for all requests for cost recovery.

Enbridge Gas will need to fully demonstrate the prudence of its actions particularly with regard to the risks of successful implementation of IRPAs and the potential for assets becoming stranded.

10 MONITORING AND REPORTING

Enbridge Gas shall file an annual IRP report with the OEB as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, the proceeding in which it may seek disposition of balances in the IRP Costs deferral accounts.

The OEB does not intend to approve the annual IRP report, but it could impact the OEB's findings on the disposition of amounts in the IRP Costs deferral accounts, or inform future proceedings.

The annual IRP report and the report from the IRP Technical Working Group are to be filed for information regardless of whether Enbridge Gas is seeking approval to clear any balances in the IRP Costs deferral accounts.

The annual IRP report should include the following information:

- A summary of IRP stakeholdering activities from the past year
- A summary of IRP engagement or consultation activities with Indigenous peoples
- Updates on IRP pilot projects underway
- Updates on incorporating IRP into asset management planning
- Updates on status of potential IRP Plans
- Updates on status of approved IRP Plans, including details of adjustments made by Enbridge Gas
- Annual and cumulative summaries of actual peak demand reductions/energy savings generated by each IRP Plan to-date, including comparisons to the initial forecast reduction/energy savings and the actual amount of expenditure on each IRP Plan to-date
- The most recent results of Enbridge Gas's IRP Assessment Process for system needs, including reporting on those system needs where a negative binary screening or technical/economic evaluation resulted in no further assessment of IRPAs
- A summary of best available information on demand-side IRPAs, including types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas's system, and learnings from pilot projects and other jurisdictions
- Efforts taken to explore the use of interruptible rates for meeting system needs, including how customers have been provided the opportunity to consider this option
- Any other IRP-related matters established by the OEB.

11 IRP COSTS DEFERRAL ACCOUNTS

The OEB determined in the IRP Decision and Order that two IRP Costs deferral accounts will be established for the period from 2021 to 2023, to track incremental IRP-related costs not included in base rates during the current deferred rebasing term. Enbridge Gas will be preparing a Draft Accounting Order for the two IRP Costs deferral accounts, based on the guidance in the Decision and Order. Enbridge Gas will follow the approved Accounting Order for the use of these accounts.

Enbridge Gas may request disposition of account balances, when eligible, as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application. Costs in the IRP Operating Costs Deferral Account for general IRP administrative costs may be brought forward for disposition without any prior approval. Costs in this account related to specific projects (e.g. project operating and maintenance costs, enabling payments to competitive service providers) should not be brought forward for disposition until an IRP Plan has been approved. When an IRP Plan has been approved and the project is considered to be “in-service”, Enbridge Gas is also eligible to seek cost recovery of the project’s capital-related revenue requirement through the IRP Capital Costs Deferral Account.

The balances brought forward for disposition in the IRP Costs deferral accounts should be based on actual expenditures. The balance for the IRP Capital Costs Deferral Account will include the revenue requirement impacts associated with project costs eligible for inclusion in rate base. The application to clear any balance in the IRP Capital Costs Deferral Account should describe the reasons for any variance between actual costs and the forecast costs that were included in the IRP Plan approval.

12 IRP PILOT PROJECTS

Enbridge Gas is expected to develop and implement two IRP pilot projects. The pilots are expected to be an effective approach to understand and evaluate how IRP can be implemented to avoid, delay or reduce facility projects.

The OEB expects that the IRP pilot projects will be selected and deployed by the end of 2022. The detailed consideration of IRP pilot projects should commence shortly after the issuance of the IRP Framework with input being sought from the IRP Technical Working Group.

The nature of the pilots should be responsive to the opportunities that arise. Enbridge Gas should then apply to the OEB for approval of the IRP pilot projects providing the information and following the approach for IRP Plans, described in chapter 9 ("Future IRP Plan Applications").

The implementation of pilots should not be a barrier to addressing a system need through a non-pilot IRP Plan, if an exceptional time-limited opportunity arises prior to the completion of the pilots.

Enbridge Gas should share key learnings from the pilots through reporting to the OEB and stakeholders, through the annual IRP report and more frequent updates to the IRP Technical Working Group, as needed. This experience will facilitate the development of other IRP Plans and identify areas for enhancement to the IRP Framework.

The IRP pilot project costs are to be tracked in the IRP Costs deferral accounts, and recovery can be requested annually for prudently incurred costs.

Enbridge Gas is encouraged to use the IRP pilot projects as a testing ground for an enhanced DCF+ test as discussed in section 5.3 ("Two-Stage Evaluation Process").

1977 CarswellOnt 328
Ontario Divisional Court

Dawn (Township) Restricted Area By-Laws 40 of 1973 & 52 of 1974, Re

1977 CarswellOnt 328, [1977] 1 A.C.W.S. 365, [1977] O.J. No. 2223, 15 O.R. (2d) 722, 2 M.P.L.R. 23, 76 D.L.R. (3d) 613, 7 O.M.B.R. 300 (note)

Union Gas Ltd. v. Corporation Of Township Of Dawn

Tecumseh Gas Storage Ltd. v. Township Of Dawn

Keith, Maloney and Donohue JJ.

Heard: January 24, 1977
Judgment: February 22, 1977

Proceedings: reversed *Dawn (Township) Restricted Area By-Laws 40 of 1973 & 52 of 1974, Re* (1975), 1975 CarswellOnt 1123, 4 O.M.B.R. 462 ((O.M.B.))

Counsel: *J.J. Robinette* , Q.C. and *L.G. O'Connor* , Q.C., for appellant Union Gas Ltd.
P.Y. Atkinson , for appellant Tecumseh Gas Storage Ltd.
W.B. Williston , Q.C., for respondent Township of Dawn.
T.H. Wickett , for Ontario Energy Board.

The judgment of the Court was delivered by *Keith J.* :

1 Pursuant to leave granted by this Court on 24th November 1975, upon application made in accordance with s. 95(1) of The Ontario Municipal Board Act, R.S.O. 1970, c. 323, the following questions are submitted to this Court for its opinion:

(a) Is s. 4.2.3. of By-law 40 of the Township of Dawn as amended, ultra vires of the respondent municipality?

(b) Is the Ontario Municipal Board therefore without jurisdiction to approve the respondent's By-law 40 as amended including s. 4.2.3. thereof?

2 The Township of Dawn in the County of Lambton, a rural agricultural township in south western Ontario, passed its first comprehensive zoning by-law on 18th June 1973 (By-law No. 40) and amending By-law (No. 52) on 3rd September 1974.

3 These two by-laws came before the Ontario Municipal Board on the 16th and 24th April 1975, for approval. In addition to the parties appearing in this Court, two other parties interested in the effect of these by-laws were represented at the Municipal Board hearings, but the Ontario Energy Board, one of the most vitally interested parties, inexplicably was not.

4 The relevant sections of the by-laws as amended read as follows:

1.1 Section 1 — Introduction

Whereas the Council has authority to regulate the use and nature of land, buildings and structures in the Township of Dawn by by-law subject to the approval of the Ontario Municipal Board and deems it advisable to do so.

1.2 Now therefore the Council of the Corporation of the Township of Dawn enacts as follows:

Title

2.1 This by-law shall be known as the 'Zoning By-law' of the Township of Dawn.

Penalty

3.3.1 Every person who contravenes by-law is guilty of an offence and liable upon conviction to fine of not more than three hundred (300) dollars for each offence, exclusive of costs. Every such fine is recoverable under the Summary Convictions Act, all the provisions of which apply except that the imprisonment may be for a term of not more than twenty-one (21) days.

3.3.2 Where a person, guilty of an offence under this by-law has been directed to remedy any violation and is in default of doing such matter or thing required, then such matter or thing may be done at his expense, by the Corporation of the Township of Dawn and the Corporation may recover the expense incurred in doing it by action or the same may be recovered in like manner as municipal taxes.

Section 4 — General Use and Zone Regulations

4.1 Uses Permitted.

4.1.1. No land, building or structure shall be used or occupied and no building or structure or part thereof shall be erected or altered except as permitted by the provisions of this by-law.

4.2.3. Except as limited herein nothing in this by-law shall prevent the use of any land as a right-of-way, easement or corridor for any oil, gas, brine or other liquid product pipeline and appurtenances thereto, but no appurtenances in the form of a metering, booster, dryer, stipper or pumping station, shall be constructed closer than 500 feet to any adjacent residential or commercial zone or rural residence, except as otherwise provided. All transmission pipelines to be installed from or to a production, treatment or storage site shall be constructed from or to such site to and along, in or upon a right-of-way, easement or corridor located as follows:

(a) running northerly or southerly within 100 feet perpendicular distance from the centre line dividing the east and west halves of a concession lot;

(b) running easterly and westerly within 100 feet perpendicular distance from a concession lot line not being a township, county or provincial road or highway;

(c) across, but not along a township, county or provincial road or highway.

Nothing herein shall prevent the location of a local distribution gas service line upon any street, road or highway.

5 On 20th May 1975, the Ontario Municipal Board released its decision approving of By-law 40 as amended. The reasons are devoted almost exclusively to s. 4.2.3 as amended and the objections of the appellants thereto. To fully understand the approach taken by the Municipal Board, the following extracts from these reasons are quoted:

> The township consists of flat agricultural land with soil rated in the Canada Land Survey as A2. The Board was advised by the representative of the Ministry of Agriculture and Food that the soil is of the Brookston clay type which requires particular attention to drainage because the land is so flat and that this was the reason it was rated A2 rather than A1. The soil is very productive if properly drained and worked. As drainage is installed the soil responds to cash crops such as corn and soya beans. Drainage is accomplished generally by a grid system of tile drainage lines approximately 40 feet apart throughout the whole of the township. These feed into municipal drains which generally follow lot and concession lines and eventually drain to the south-west into the Sydenham River. An example of this method of drainage in the township is shown on Exhibit 9, filed. This also indicates the position of the Union Gas Company pipeline which runs in a diagonal direction across the tile drains referred to above. Because the pipeline runs across the drains, a header line is required to direct the flow of the water into the municipal drain.

The evidence indicates that in respect of the pipeline installation on a right-of-way that may be 60 feet wide or more, and the header line parallel to it, the farmer in using his equipment must gear down each time before crossing these installations rather than continuing in the usual sweep of the farmland. This time-consuming and inconvenient operation is necessary every time the farmer crosses the pipeline easement area. In addition, the evidence clearly indicated that upon excavation for the pipeline, the soil composition is disturbed and impacted so that growth is hampered for several years until the soil is returned to its normal state. The Company indicated in evidence that a new method for laying lines and conserving the topsoil for future development had been devised. This may alleviate the problems, but only time will tell.

The Union Gas Limited (hereinafter to be referred to as 'the Company') operates in the south-west part of the province and has important connections with Consumers' Gas Company of Toronto and other systems for whom it stores gas in the summer months for delivery in the winter. The relationship of the Union Gas Limited operation to other systems in the province are well illustrated on Exhibit 33, filed. The hub of their system is in Dawn Township from which all the distribution and transmission lines radiate. The importance of the Company to the municipality is illustrated by Exhibit 26 filed, which shows that for the years 1970 to 1974 inclusive, the Company paid taxes which formed a significant portion of the total township levy varying from 24.3 per cent to 30.6 per cent in those years.

The by-law provides that transmission lines are to be laid in corridors 200 feet wide running along the half lot lines in a north-south direction and along concession lines in an east-west direction, 'across but not along a township, county or provincial road or highway', Section 4.2.3.

This corridor concept was the chief source of objection registered by the Company which in evidence indicated that the corridor method of laying their lines would be very costly. This was particularly so when some of the existing lines are now laid in a diagonal direction. When new looping lines are required they are now planned to run generally parallel to the existing lines. If they were to follow the corridors the length of line would be increased, in some cases the diameter of the pipe would have to be greater, and perhaps they might also require additional compression facilities. The additional costs were shown to be large and would result in increased costs to the public.

The Board must weight the possibility of incurring these increased costs against the need for protecting the farm industry against unnecessary and unplanned disturbance in future years. There was ample evidence to indicate that the need for pipeline installations would increase in the future. There was also evidence to indicate that about 50 per cent of the existing lines are already built in a north-south and east-west direction and that the corridor concept has therefore in fact found practical use in the past. (Exhibits 7 and 27). It was the argument of counsel for the applicant that once the corridors were established the extra cost for looping will not be as significant.

Argument of counsel for the Tecumseh Gas Storage Limited was that the use of land for pipelines was not in fact a use of land as envisaged under Section 35(1)1 of The Planning Act. To bolster this argument counsel referred the Board to the case of *Pickering Township v. Godfrey* reported in 1958 Ontario Reports, page 429. The Board finds that the instant case can be distinguished from the quoted case which dealt specifically with the making of a quarry or gravel pit as a 'land use'. In addition, the Board finds that the use of land for installation of a pipeline fits the definition arrived at in the case above quoted as meaning 'the employment of the property for enjoyment, revenue or profit without in any way otherwise diminishing or impairing the property itself'. (p. 427, second paragraph).

The second major argument of counsel was that the municipality has no jurisdiction to deal with pipeline installation because of the existence of The Ontario Energy Board Act which creates the Ontario Energy Board and gives it jurisdiction to determine the route for a transmission line, production line, distribution line or a station (Section 40(1)). The Board was also referred to Section 57 of The Ontario Energy Board Act which reads as follows:

> 57(1) In the event of conflict between this Act and any other general or special Act, this Act prevails.
>
> (2) This Act and the regulations prevail over any by-law passed by a municipality.

In the opinion of the Board the above section provides only for the event of a conflict between The Ontario Energy Board Act and any other Act. It does not, nor can it be interpreted to mean that no other Act can be effective. It does not in the opinion of the Board prohibit the municipality from dealing with those matters referred to in Section 35 of The Planning Act.

The major considerations of the Ontario Energy Board are not directed towards planning. It is the responsibility and duty of council to plan for the proper and orderly development of the municipality having regard to the health, safety, convenience and welfare of the present and future inhabitants of the municipality, all within the framework of The Planning Act.

The Board is of the opinion that zoning by-laws must provide for all ratepayers a degree of certainty for reasonable stability. This can be accomplished by passing restricted area by-laws for land use on a planning basis with proper and responsible study and public input. The evidence indicates that the municipality has indeed acted in a reasonable and responsible manner to achieve this end. The consideration for the farming community which forms a large proportion of the municipality is a proper and reasonable one. There is no certainty as to where the Ontario Energy Board may finally decide to place the pipelines required by the criteria they have and will develop. They will, however, have the legislative document before them giving the corporate expression of the municipality to indicate where, on the basis of planning considerations, the pipelines should go. The Ontario Energy Board will then, on the basis of its criteria and the evidence heard, be in a position to give its decision on the ultimate route chosen.

In the meantime, the municipality will by legislation inform all its ratepayers where the pipelines should be laid. The farmer will be able to proceed with the least amount of interference both during construction of pipelines on or near his lands and indeed in his everyday work. The pipeline companies will benefit from this as well. With less interference to the farmer there should be fewer difficulties experienced both in the installation of the pipelines and the servicing and maintenance of the pipelines and the tile drain systems.

6 By-law 40 as amended was enacted by the council of the respondent in accordance with the powers given to municipal councils by s. 35 of The Planning Act, R.S.O. 1970, c. 349. The relevant portions of that section read as follows:

35. — (1) By-laws may be passed by the councils of municipalities:

1. For prohibiting the use of land, for or except for such purposes as may be set out in the by-law within the municipality or within any defined area or areas or abutting on any defined highway or part of a highway.

2. For prohibiting the erection or use of buildings or structures for or except for such purposes as may be set out in the by-law within the municipality or within any defined area or areas or upon land abutting on any defined highway or part of a highway.

7 Section 46 of The Planning Act is identical with s. 57(1) of The Ontario Energy Board Act, R.S.O. 1970, c. 312 quoted in the reasons of the Ontario Municipal Board. Fortunately, s. 46 of The Planning Act has no equivalent to s. 57(2) of The Ontario Energy Board Act or the Court might well have been forced to assert that its views prevailed over one or other or both of the statutes.

8 The appellant Union Gas operates an extensive network of natural gas transmission lines throughout south-western Ontario delivering this energy to customers, both wholesale and retail, extending from Windsor on the south-west, to Hamilton and Trafalgar on the east and Goderich and Owen Sound on the north.

9 It supplies scores of city, town and village municipalities in this extensive and heavily populated area and its lines traverse 16 counties which contain upwards of 140 township municipalities. The municipal councils of each of these has the same power under The Planning Act to pass zoning by-laws.

10 The principal source of the supply of natural gas to Union Gas is the Trans-Canada pipeline which enters the southern part of Ontario in Lambton County just south of Sarnia and connects with a major compressor station of Union Gas in the

Township of Dawn. There are four other major compressor stations operated by this appellant, one just west of London, another at Trafalgar between Hamilton and Toronto, one near Simcoe and the fourth south of Chatham. These stations are essential to maintain pressure throughout the pipeline network.

11 In addition, Union Gas lines serve as feeders for companies like the Consumers' Gas Company serving Metropolitan Toronto and another extensive area of Ontario.

12 In addition, a significant portion of the source of natural gas transmitted by Union Gas, comes from local wells found in south-western Ontario, a number of which are located in the Township of Dawn.

13 The company also maintains reserves of gas in natural underground storage fields, some but by no means all of which are also located in the Township of Dawn.

14 The local wells and the storage fields must all be connected to the distribution lines and the compressor stations.

15 The second appellant, Tecumseh Gas Storage Limited, is equally affected by the impugned by-law, but no detailed description of its operations was presented to the Court.

16 I have stressed these points to illustrate firstly how insignificant are the local problems of the Township of Dawn when viewed in the perspective of the need for energy to be supplied to those millions of residents of Ontario beyond the township borders, and to call to mind the potential not only for chaos but the total frustration of any plan to serve this need if by reason of powers vested in each and every municipality by The Planning Act, each municipality were able to enact by-laws controlling gas transmission lines to suit what might be conceived to be local wishes. We were informed that other township councils have only delayed enacting their own by-laws pending the outcome of this appeal.

17 At the conclusion of the argument of this appeal I informed counsel, on behalf of the Court, that the appeal book had been endorsed as follows:

> The appeal will be allowed with costs. In view of the importance of the issue, which is raised in this appeal insofar as it relates specifically to the Energy Board's jurisdiction as challenged by a municipal council, and in deference to the lengthy reasons delivered by the Ontario Municipal Board, the Court will in due course, deliver considered reasons which will be the basis of the formal order of the Court.

18 It is not necessary for my purpose to trace the history and origins of the present Ontario Energy Board Act, as amended. Reference to s. 58 of the present act will suffice to show that this industry has developed over many years under provincial legislation. Section 58 reads as follows:

> 58. Every order and decision made under,
>
> (*a*) *The Fuel Supply Act* , being chapter 152 of the Revised Statutes of Ontario, 1950;
>
> (*b*) *The Natural Gas Conservation Act* , being chapter 251 of the Revised Statutes of Ontario, 1950;
>
> (*c*) *The Well Drillers Act* , being chapter 423 of the Revised Statutes of Ontario, 1950;
>
> (*d*) *The Ontario Fuel Board Act, 1954;*
>
> (*e*) *The Ontario Energy Board Act, 1960;*
>
> (*f*) *The Ontario Energy Act* , being chapter 271 of the revised Statutes of Ontario, 1960; or
>
> (*g*) *The Ontario Energy Board Act, 1964* . that were in force on the day the Revised Statutes of Ontario, 1970 is proclaimed in force shall be deemed to have been made by the Board under this Act.

19 Pursuant to s. 2 [am. 1973, c. 55, s. 1] of the Act, the Ontario Energy Board is composed of not less than five members appointed by the Lieutenant Governor in Council. It has an official seal, and its orders which must be judicially noticed are not subject to The Regulations Act, R.S.O. 1970, c. 410.

20 By s. 14, many of the powers of the Supreme Court of Ontario are vested in this Board "for the due exercise of its jurisdiction".

21 Section 18 is important having regard to the penalty provisions of the township by-law quoted above. That sections reads as follows:

> 18. An order of the Board is a good and sufficient defence to any action or other proceeding brought or taken against any person in so far as the act or omission that is the subject of such action or other proceeding is in accordance with the order.

22 Section 19 [am. 1973, c. 55, s. 5(1), (2)] vests power in the Board to fix rates and other charges for the sale, transmission, distribution and storage of natural gas.

23 Under s. 23 [am. 1973, c. 55, s. 8] the Board is charged with responsibility to issue permits to drill gas wells.

24 Section 25 prohibits any company in the business of transmitting, distributing or storing gas from disposing of its plant by sale or otherwise without leave, and such leave cannot be granted without, inter alia, a public hearing.

25 Section 30 provides that any order of the Board may be filed with the Registrar of the Supreme Court and is enforceable in the same way as a judgment or order of the Court.

26 Part II of the Act deals specifically with pipe lines and I quote s. 38(1), s. 39, s. 40(1), (2), (3), (8), (9) and (10), s. 41(1), (3) and s. 43(1) and (3):

> 38. — (1) No person shall construct a transmission line without first obtaining from the Board an order granting leave to construct the transmission line.
>
> 39. Any person may, before he constructs a production line, distribution line or station, apply to the Board for an order granting leave to construct the production line, distribution line or station.
>
> 40. — (1) An applicant for an order granting leave to construct a transmission line, production line, distribution line or a station shall file with his application a map showing the general location of the proposed line or station and the municipalities, highways, railways, utility lines and navigable waters through, under, over, upon or across which the proposed line is to pass.
>
> (2) Notice of the application shall be given by the applicant in such manner as the Board directs and shall be given to the Department of Agriculture and Food, the Department of Municipal Affairs, the Department of Highways and such persons as the Board may direct.
>
> (3) Where an interested person desires to make objection to the application, such objection shall be given in writing to the applicant and filed with the Board within fourteen days after the giving of notice of the application and shall set forth the grounds upon which such objection is based.
>
> 40. — (8) Where after the hearing the Board is of the opinion that the construction of the proposed line or station is in the public interest, it may make an order granting leave to construct the line or station.
>
> (9) Leave to construct the line or station shall not be granted until the applicant satisfies the Board that it has offered or will offer to each landowner an agreement in a form approved by the Board.

(10) Any person to whom the Board has granted leave to construct a line or station, his officers, employees and agents, may enter into or upon any land at the intended location of any part of the line or station and may make such surveys and examinations as are necessary for fixing the site of the line or station, and, failing agreement, any damages resulting therefrom shall be determined in the manner provided in section 42.

41. — (1) Any person who has leave to construct a line or station under this Part or a predecessor of this Part may apply to the Board for authority to expropriate land for the purposes of the line or station, and the Board shall thereupon set a date for the hearing of such application, and such date shall be not fewer than fourteen days after the date of the application, and upon such application the applicant shall file with the Board a plan and description of the land required, together with the names of all persons having an apparent interest in the land.

41. — (3) Where after the hearing the Board is of the opinion that the expropriation of the land is in the public interest, it may make an order authorizing the applicant to expropriate the land.

43. — (1) Any person who has leave to construct a line may apply to the Board for authority to construct it upon, under or over a highway, utility line or ditch.

43. — (3) Without any other leave and notwithstanding any other Act, where after the hearing the Board is of the opinion that the construction of the line upon, under or over a highway, utility line or ditch, as the case may be, is in the public interest, it may make an order authorizing the applicant so to do upon such terms and conditions as it considers proper.

27 Finally, with respect to the statute itself, it may not be amiss to again quote s. 57:

57. — (1) In the event of conflict between this Act and any other general or special Act, this Act prevails.

(2) This Act and the regulations prevail over any by-law passed by a municipality.

28 In my view this statute makes it crystal clear that all matters relating to or incidental to the production, distribution, transmission or storage of natural gas, including the setting of rates, location of lines and appurtenances, expropriation of necessary lands and easements are under the exclusive jurisdiction of the Ontario Energy Board and are not subject to legislative authority by municipal councils under The Planning Act.

29 These are all matters that are to be considered in the light of the general public interest and not local or parochial interests. The words "in the public interest" which appear, for example, in ss. 40(8), 41(3) and 43(3) which I have quoted, would seem to leave no room for doubt that it is the broad public interest that must be served. In this connection it will be recalled that s. 40(1) speaks of the requirement for filing a general location of proposed lines or stations showing "the municipalities, highways, railways, utility lines and navigable waters through, under, over, upon or across which the proposed line is to pass".

30 Persons affected must be given notice of any application for an order of the Energy Board and full provision is made for objections to be considered and public hearings held.

31 In the final analysis, however, it is the Energy Board that is charged with the responsibility of making a decision and issuing an order "in the public interest".

32 While the result in the case of *Campbell-Bennett Ltd. v. Comstock Midwestern Ltd.*, [1954] S.C.R. 207, [1954] 3 D.L.R. 481 , might perhaps be different today, having regard to the facts of that case and subsequent federal legislation, the principles enunciated are valid and applicable to the case before this Court.

33 In the *Campbell-Bennett* case, the defendant Trans Mountain Pipe Line was incorporated by a special act of the Parliament of Canada to construct inter-provincial pipe lines. During the course of construction of a pipe line from Acheson, Alberta to Burnaby, British Columbia, some work was done in British Columbia by the plaintiff for which it claimed to be entitled to a

mechanics' lien on the works in British Columbia, and to enforce that lien under the British Columbia Mechanics' Lien Act, R.S.B.C. 1960, c. 238 by seizing and selling a portion of the pipe line.

34 At p. 212 Kerwin J. (as he then was) on behalf of himself and Fauteux J. (as he then was) said "The result of an order for the sale of that part of Trans Mountain's oil pipe line in the County of Yale would be to break up and sell the pipe line piecemeal, and a provincial legislature may not legally authorize such a result."

35 Then at pp. 213 to 215, Rand J. on behalf of himself and the other three members of the Court said:

> The respondent, Trans Mountain Oil Pipe Line Company, was incorporated by Dominion statute, 15 Geo. VI, c. 93. It was invested with all the 'powers, privileges and immunities conferred by' and, except as to provisions contained in the statute which conflicted with them, was made subject to all the 'limitations, liabilities and provisions of any general legislation relating to pipe lines for the transportation of oil' enacted by Parliament. Within that framework, it was empowered to construct or otherwise acquire, operate and maintain interprovincial and international pipe lines with all their appurtenances and accessories for the transportation of oil.
>
> The *Pipe Lines Act* , R.S.C. 1952, c. 211, enacted originally in 1949, is general legislation regulating oil and gas pipe lines and is applicable to the company. By its provisions the company may take land or other property necessary for the construction, operation or maintenance of its pipe lines, may transport oil and may fix tolls therefor. The location of its lines must be approved by the Board of Transport Commissioners and its powers of expropriation are those provided by the *Railway Act* . By s. 38 the Board may declare a company to be a common carrier of oil and all matters relating to traffic, tolls or tariffs become subject to its regulation. S. 10 provides that a company shall not sell or otherwise dispose of any part of its company pipe line, that is, its line held subject to the authority of Parliament, nor purchase any pipe line for oil transportation purposes, nor enter into any agreement for amalgamation, nor abandon the operation of a company line, without leave of the Board; and generally the undertaking is placed under the Board's regulatory control.
>
> Is such a company pipe line so far amenable to provincial law as to subject it to statutory mechanics' liens? The line here extends from a point in Alberta to Burnaby in British Columbia. That it is a work and undertaking within the exclusive jurisdiction of Parliament is now past controversy: *Winner v. S.M.T. (Eastern) Limited* ([1951] S.C.R. 887), affirmed, with a modifi cation not material to this question, by the Judicial Committee but as yet unreported. The lien claimed is confined to that portion of the line within the County of Yale, British Columbia. What is proposed is that a lien attaches to that portion of the right of way on which the work is done, however small it may be, or wherever it may be situated, and that the land may be sold to realize the claim. In other words, an interprovincial or international work of this nature can be disposed of by piecemeal sale to different persons and its undertaking thus effectually dismembered.
>
> In the light of the statutory provisions creating and governing the company and its undertaking, it would seem to be sufficient to state such consequences to answer the proposition. The undertaking is one and entire and only with the approval of the Board can the whole or, I should say, a severable unit, be transferred or the operation abandoned. Apart from any question of Dominion or Provincial powers and in the absence of clear statutory authority, there could be no such destruction by means of any mode of execution or its equivalent. From the earliest appearance of such questions it has been pointed out that the creation of a public service corporation commits a public franchise only to those named and that a sale under execution of property to which the franchise is annexed, since it cannot carry with it the franchise, is incompatible with the purposes of the statute and incompetent under the general law. Statutory provisions, such as s. 152 of the *Railway Act* , R.S.C. (1952), c. 234, have modified the application of the rule, but the sale contemplated by s. 10 of the *Pipe Lines Act* is a sale by the company, not one arising under the provisions of law and in a proceeding *in invitum* . The general principle was stated by Sir Hugh M. Cairns, L.J. in *Gardner v. London, Chatham and Dover Railway* ((1867), L.R. 2 Ch. 201 at 212):
>
> > When Parliament, acting for the public interest, authorizes the construction and maintenance of a railway, both as a highway for the public, and as a road on which the company may themselves become carriers of passengers and goods, it confers powers and imposes duties and responsibilities of the largest and most important kind, and it confers and

> imposes them upon the company which Parliament has before it, and upon no other body of persons. These powers must be executed and these duties discharged by the company. They cannot be delegated or transferred.

In the same judgment and speaking of the effect of an authorized mortgage of the 'undertaking' he said:

> The living and going concern thus created by the Legislature must not, under a contract pledging it as security, be destroyed, broken up, or annihilated. The tolls and sums of money ejusdem generis — that is to say, the earnings of the undertaking — must be made available to satisfy the mortgage; but, in my opinion, the mortgagees cannot; under their mortgages, or as mortgagees — by seizing, or calling on this Court to seize, the capital, or the lands, or the proceeds of sales of land, or the stock of the undertakings — either prevent its completion, or reduce it into its original elements when it has been completed.

36 Several further and compelling submissions were made to the Court on behalf of the appellants, but having regard to the first submission which is irresistible and of fundamental importance, I do not think it necessary to deal with all of the arguments advanced.

37 Reference should be made, however, to two of them. First, attention should be directed to An Act to Regulate the Exploration and Drilling for, and the Production and Storage of Oil and Gas, commonly referred to as The Petroleum Resources Act, 1971 (Ont.), c. 94.

38 The objects of this legislation can be readily understood by reference to s. 17(1) of the statute which reads as follows:

17. — (1) The Lieutenant Governor in Council may make regulations,

(*a*) for the conservation of oil or gas;

(*b*) prescribing areas where drilling for oil or gas is prohibited;

(*c*) prescribing the terms and conditions of oil and gas production leases and gas storage leases or any part thereof, excluding those relating to Crown lands, and providing for the making of statements or reports thereon;

(*d*) regulating the location and spacing of wells;

(*e*) providing for the establishment and designation of spacing units and regulating the location of wells in spacing units and requiring the joining of the various interests within a spacing unit or pool;

(*f*) prescribing the methods, equipment and materials to be used in boring, drilling, completing, servicing, plugging or operating wells;

(*g*) requiring operators to preserve and furnish to the Department drilling and production samples and cores;

(*h*) requiring operators to furnish to the Department reports, returns and other information;

(*i*) requiring dry or unplugged wells to be plugged or replugged, and prescribing the methods, equipment and materials to be used in plugging or replugging wells;

(*j*) regulating the use of wells and the use of the subsurface for the disposal of brine produced in association with oil and gas drilling and production operations.

39 The importance of this Act is reflected in s. 18 which reads as follows:

18. — (1) In the event of conflict between this Act and any other general or special Act, this Act, subject only to *The Ontario Energy Board Act, 1964* , prevails.

(2) This Act and the regulations prevail over any municipal by-law.

40 Similarly, although it was not referred to in argument, The Energy Act, R.S.O. 1970, c. 148 [repealed by 1971, Vol. 2, c. 44, s. 32] deals with other aspects of the natural gas and oil industry. The objects of the legislation are set out in s. 12(1) which I need not quote, but again s. 13 of this Act is identical in its wording to s. 18 of The Petroleum Resources Act quoted above.

41 The second of the additional submissions to which reference should be made is based on a cardinal rule for the interpretation of statutes and expressed in the maxim "*generalia specialibus non derogant* ". For a discussion of the effect of this rule I will only refer to the case of *Ottawa v. Eastview*, [1941] S.C.R. 448, [1941] 4 D.L.R. 65 commencing at p. 461, and to the Dictionary of English Law (Earl Jowitt) at p. 862.

42 In the case before this Court, it is clear that the Legislature intended to vest in the Ontario Energy Board the widest powers to control the supply and distribution of natural gas to the people of Ontario "in the public interest" and hence must be classified as special legislation.

43 The Planning Act, on the other hand, is of a general nature and the powers granted to municipalities to legislate with respect to land use under s. 35 [am. 1972, c. 118, s. 6(1)] of that Act must always be read as being subject to special legislation such as is contained, for example, in The Ontario Energy Board Act, The Energy Act and The Petroleum Resources Act.

44 In the result therefore, and in response to the questions with respect to which leave to appeal was granted, this Court certifies to the Ontario Municipal Board:

(a) Section 4.2.3. of By-law 40 as amended, of the Township of Dawn is ultra vires the said municipality, and

(b) The Ontario Municipal Board therefore is without jurisdiction to approve the said by-law as amended in its present form by reason of s. 4.2.3. thereof.

45 This Court further certifies that should the Ontario Municipal Board see fit to exercise the powers vested in it by s. 87 of The Ontario Municipal Board Act, the said By-law 40 as amended may be approved after deleting from s. 4.2.3. the words "Except as limited herein" at the commencement of the said section and all the words after the word "thereto" in the fourth line of the said by-law as printed down to and including the words "road or highway" in sub-clause (c) of the said s. 4.2.3., so that s. 4.2.3. as so approved would read:

> Nothing in this by-law shall prevent the use of any land as a right-of-way, easement or corridor for any oil, gas, brine or other liquid product pipeline and appurtenances thereto.
>
> Nothing herein shall prevent the location of a local distribution gas service line upon any street, road or highway.

46 The appellants and the Ontario Energy Board are entitled to their costs of this appeal.

Appeal allowed.

EB-2011-0065
EB-2011-0068

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by ACH Limited Partnership for a licence amendment pursuant to section 74 of the *Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF an application by AbiBow Canada Inc. for a licence amendment pursuant to section 74 of the *Ontario Energy Board Act, 1998.*

AND IN THE MATTER OF a request by the First Nations Group to stay the Board's order pursuant to section 33(6) of the *Ontario Energy Board Act, 1998.*

BEFORE: Paul Sommerville
Presiding Member

Cynthia Chaplin
Vice Chair

DECISION

BACKGROUND

ACH Limited Partnership ("ACH") filed an application on March 3, 2011 for an amendment to Schedule 1 of its electricity generator licence EG-2006-0124 to reflect a change to ACH's status as owner of eight hydroelectric generating stations to owner and operator.

AbiBow Canada Inc. (“AbiBow”, and, together with ACH, the “Applicants”), filed an application on March 7, 2011 for an amendment to its electricity generation licence EG-2003-0204 to change the name on the licence from Abitibi Consolidated Company of Canada to AbiBow Canada Inc., and to remove eight hydroelectric generating stations, which AbiBow currently operates, from Schedule 1 of its licence.

On May 20, 2011, after considering the applications and submissions from the Applicants and Keshen Major Law firm (“Keshen Major”) on behalf of twelve First Nations (the “First Nations group”), the Board issued a decision and order (the “Decision”) granting the Applicants the requested amendments pending confirmation from the Applicants that the commercial transaction has closed and operation of the eight generation stations has been transferred to ACH from AbiBow.

On May 24, 2011 Keshen Major on behalf of the First Nations group filed a letter notifying the Board of the First Nations group’s intention to appeal the Board’s Decision to the Divisional Court and requesting the Board to stay its order pending appeal of the Decision.

On May 24, 2011 counsel for the Applicants filed a response on the stay application of the First Nations group objecting to the First Nations group’s request for a stay with reasons.

On May 27, 2011 the Applicants filed a letter advising the Board that the commercial transaction to buy and sell the interest in ACH closed on May 27, 2011.

On May 27, 2011 the First Nations group filed further submissions in response to the Applicants’ submissions. The First Nations group asserted that its request for a stay did meet the applicable test. Specifically, it asserted that the precedent relied upon by the Applicants respecting the “serious issue to be decided” component held that the threshold for the seriousness of the issue is a low threshold. In addition, the First Nations group argues that the Board ought not to make a finding that there is no serious issue to be decided on the basis of presumed, rather than established facts.

As to the “irreparable harm” component of the test, the First Nations group re-asserts in its Reply submission that irreparable harm ought not to be the standard applied where the duty to consult is in issue and that the “potential adverse impact test” is the appropriate test, with reference to passages from the Haida Nation decision.

Finally, the Reply submission contends that with respect to the “balance of convenience” component of the test, that the Applicants have not substantiated through evidence their claims of financial harm.

DECISION

The Board will not grant a stay of its order as requested by the First Nations group.

The test

The three part test to determine whether a stay application should be granted was set out in *RJR-MacDonald Inc. v. Canada (Attorney General)*[1]:

a. There is a serious issue to be decided,
b. The applicant for the stay will suffer irreparable harm if a stay is not granted, and
c. The balance of convenience favours the granting of a stay because the harm to the applicant outweighs any potential harm to the respondent.

All three components of the test must be met.

Both the First Nations group and the Applicants agree that this is the appropriate test (with a caveat from the First Nations group with respect to the irreparable harm portion of the test, which is discussed below).

Serious issue to be decided

The First Nations group argues that the seriousness of the Crown’s duty to consult with First Nations where their interests may be adversely affected can hardly be doubted. The Board does not dispute that. However, the general existence of the duty to consult is not the issue in this case. The issue to be considered in an application for a stay is whether there is a serious case to be made that the Board erred in its decision.

The Board is not convinced that the First Nations group has established that there is a serious matter to be decided in this case, however low the threshold. The arguments made by the First Nations group are that the duty to consult itself is important, and that

[1] (1994), 111 D.L.R. (4th) 385 (S.C.C.) (“RJR MacDonald”)

the standard of review that will be applied by the courts to the Board's decision will in all likelihood be correctness. While both of these statements may be true, they are not directly relevant to the issue of whether there is a serious issue to be decided. The decision at issue here, that is the subject of the application for stay, relates exclusively to the identity of the license holder. The Board's Decision does not have any implications with respect to any other aspect of the license. The operational considerations which motivate the First Nations group's interest in this case are not in any way affected by the Board's Decision. This falls below any arguable standard of "seriousness". There is simply no relation between the Board's Decision in this case and the interest of the First Nations group in the operation of the facilities.

Irreparable harm

The First Nations group suggests that the irreparable harm component of the test should be modified in this case to "potential adverse impact". They submit that that any higher test would undermine the purpose of the duty to consult as explained in *Haida Nation v. British Columbia (Minister of Forests)*[2]. While no authority for this proposition was provided by the First Nations group, its Reply submission pointed to some passages of Haida Nation which it asserted supported by implication its view.
The Appellants submission asserted that no modification to the irreparable harm test is warranted. They point out that the RJR MacDonald test is referred to in Haida Nation itself, and that there have been no cases indicating that a different standard is to apply in an Aboriginal context.

The Board finds that the irreparable harm portion of the test applies as described in RJR MacDonald, and that the First Nations group has not demonstrated that it will suffer irreparable harm if a stay is not granted. As described in the Decision, any adverse impacts to an Aboriginal right to harvest wild rice will arise only if there are changes to water levels or flows. The Decision authorizes no such changes, and indeed the Board has no authority over such matters in any event. Any possible future changes to water levels or flows must be authorized by a separate authority, according to its own processes, and are not imminent. The First Nations group has not demonstrated, or even argued, that there will be irreparable harm if the Decision is not stayed.

[2] [2004] 3 S.C.R. 511 ("Haida Nation")

In the alternative, the Board is not convinced that even if the standard advanced by the First Nations group, that is "potential adverse effect" were to be adopted, that the application for a stay should succeed.
The Board's Decision in no way affects the interests of the First Nations group. The Board's Decision has the sole effect of changing the identity of the owner and operator of the facilities. It has no effect, and no potential to affect, any of the rights associated with the license, the operation of the facilities pursuant to the license, or any other aspect associated with the facilities.

Balance of convenience

The First Nations group states that it has not been established through evidence that the Applicants will suffer any harm as a result of a stay pending appeal. The First Nations group therefore argues that the status quo should be maintained, and cite a decision of the Court of Appeal:

> I am of the view that as a general rule it is in the interest of justice that the "status quo" be maintained pending an appeal where such can be done without prejudicing the interest of the successful party.[3]

The Applicants in their submissions assert that AbiBow will suffer significant financial harm if the Decision is stayed. As they indicated in a letter filed with the Board on April 21, 2011:

> Unless the Board brings this matter to a resolution shortly, the Applicant AbiBow will face significant financial harm. Specifically, June 9, 2011 is the last date on which Abitibi may redeem at a fixed price US$100MM of note using the proceeds of the sale of ACH. If the redemption does not occur by then, Abitibi would be required to use such proceeds to repurchase the notes on the open market or to continue to pay interest on such notes. … In order to be in a position to exercise its redemption right by June 9, 2011, it requires a decision by May 20, 2011.

The Appellants further note that there is no indication that the First Nations group will suffer any harm if the Decision remains in place during the appeal. As noted above, the

[3] *International Corona Resources Ltd. v. Lac Minerals Ltd.* (1986) 21 C.P.C. 2(d) 252, para. 12.

sole effect of the Board’s Decision is to change the identity of the owner and operator of the facilities. There are no other implications flowing from the Decision.

The Board finds that the balance of convenience favours the Appellants. The risk of financial harm appears to be real, and while the Applicants have not filed, and not been required to file specific evidence to this effect, the Board has no reason to question their assertions on this aspect. On the other hand, given the substantially administrative nature of the Board’s Decision in this case, there is no apparent harm of any kind to the First Nations group if the Decision is not stayed.

Conclusion

The First Nations have not met the test as established in RJR MacDonald, and the request for a stay of the Decision is denied.

DATED at Toronto, May 27, 2011

ONTARIO ENERGY BOARD

Original signed by

Paul Sommerville
Presiding Member

Original signed by

Cynthia Chaplin
Vice Chair

Ontario Energy Board | Commission de l'énergie de l'Ontario

EB-2022-0071

Hydro One Networks Inc. - Former Service Areas of Norfolk Power Distribution Inc., Haldimand County Hydro Inc., and Woodstock Hydro Services Inc.

Application for rates and other charges to be effective January 1, 2022

Motion to review and vary aspects of the EB-2021-0033 Decision and Order relating to Account 1576 and Account 1592, and a request for a partial stay of the implementation of certain aspects of the Decision

NOTICE OF HEARING, PROCEDURAL ORDER NO. 1, and DECISION ON REQUEST FOR A PARTIAL STAY
January 12, 2022

Background

Hydro One Networks Inc. (Hydro One) filed an incentive rate-setting mechanism (IRM) application with the Ontario Energy Board (OEB) on August 27, 2021, under section 78 of the *Ontario Energy Board Act*, *1998* (Act) seeking approval for changes to its electricity distribution rates to be effective January 1, 2022. The application related to the legacy service areas of the former Norfolk Power Distribution Inc. (Norfolk Power), the former Haldimand County Hydro Inc. (Haldimand County Hydro) and the former Woodstock Hydro Services Inc. (Woodstock Hydro), also referred to collectively as the Acquired Utilities. The OEB assigned file number EB-2021-0033 to the proceeding.

The OEB issued a Decision and Order (Decision) on December 16, 2021, which included subsequent procedural steps related to implementing the OEB's findings by way of a draft rate order process. Amongst other things, the Decision required Hydro One to calculate new balances in two deferral and variance accounts (Account 1576 and Account 1592) and to file those balances as part of the draft rate order process. The deadline for filing the draft rate order is January 13, 2022.

On January 7, 2022, Hydro One filed a notice of motion to review and vary the Decision. Hydro One's motion included a request for an order partially staying the implementation of the Decision pertaining to Account 1576 (for the 2016 to 2022 period) and Account 1592 (for the 2018 to 2022 period), pending the outcome of the motion. Hydro One proposed that it would otherwise proceed with the draft rate order process as set out in the Decision.

Account 1576

Hydro One's motion with respect to Account 1576 relates only to the former Woodstock Hydro. The Decision found that Hydro One should continue to record transactions, related to changes in accounting policy, in Account 1576 to the end of 2022. The OEB directed Hydro One to quantify the Account 1576 balance from 2016 to the end of 2022 in the draft rate order and dispose of this balance as part of Hydro One's rebasing application for 2023 rates.[1]

Hydro One is requesting to have the Account 1576 findings substituted with a finding that, in respect to the former Woodstock Hydro service area, Hydro One does not need to record transactions in Account 1576 for the period from 2016 to the end of 2022, and therefore revoking the direction to quantify the balance over this period and to dispose of such balance in Hydro One's 2023 rate application.

Account 1592, Sub-account CCA Changes

Hydro One's motion also concerns the former service areas of Norfolk Power, Haldimand County Hydro and Woodstock Hydro, where the OEB found that Hydro One should have balances in Account 1592, Sub-account CCA Changes, for each of the Acquired Utilities. The OEB directed Hydro One to calculate the 1592 sub-account balances to the end of 2022.

Hydro One is requesting to have the Account 1592 findings substituted with a finding that, in respect of the former service areas for each of the Acquired Utilities, it is appropriate that there are no balances in Account 1592, Sub-account CCA Changes, and therefore revoking the direction to calculate balances for the 2018 to 2022 period.

Decision on request for a Partial Stay of the Decision

Hydro One's notice of motion included a request for an order partially staying the implementation of the Decision as it relates to portions of the OEB's findings concerning Account 1576 and Account 1592. A request for a stay related to a motion to review is permitted under Rule 40.04 of the OEB's *Rules of Practice and Procedure* (Rules).

With respect to Account 1576 for Woodstock Hydro, Hydro One asked that the OEB stay the requirement in the Decision that it should:

a) continue to record transactions in Account 1576 until the end of 2022

[1] EB-2021-0110

b) quantify the forecast Account 1576 balance for 2016-2022 as part of its draft rate order filings due January 13, 2022

c) dispose of the Account 1576 balance for 2016-2022 to the legacy Woodstock Hydro customers as part of the 2023 Hydro One rebasing proceeding that is currently before the OEB

With respect to Account 1592, Hydro One requested a stay of the OEB's direction that it calculate new balances for Account 1592 on the basis described in the Decision, and to file these balances with its draft rate order.

Hydro One argued that the OEB does not intend to clear the updated balances in Account 1576 and Account 1592 in the original IRM proceeding (EB-2021-0033), and therefore it is not necessary to file the balances at this time.

Findings

There is a well-established three-part test for obtaining a stay in which the applicant must show that:

1. there a serious issue to be tried

2. it would suffer irreparable harm if the stay is not granted

3. the balance of convenience favours granting the stay[2]

Hydro One's motion does not reference this test, nor does it specifically address any of its components. Based on the submissions provided with the notice of motion, the OEB is unable to conclude that the test for a stay has been met. In particular, and without commenting on the other elements of the test, it is not clear why a stay is required to avoid irreparable harm to Hydro One.

However, as a matter of efficiency in setting rates for 2022, the OEB will not require Hydro One to file the updated balances of Account 1576 and Account 1592 with its draft rate order on January 13, 2022. It was not the OEB's intention to clear the updated balances of these accounts through rates in 2022. The balances are not required to set rates for 2022. The OEB wants to avoid the possibility of any delay in issuing 2022 rates. As the final rate order can be issued without the updated balances, the OEB will not require Hydro One to file updated Account 1576 and Account 1592 balances with the draft rate order on January 13, 2022. A decision will be made with respect to the filing of the updated balances as part of the motion to review proceeding.

[2] *RJR MacDonald Inc. v. Canada (Attorney General)* [1994] S.C.R. 311.

Service of Notice and Requests for Intervenor Status

By the issuance of this Notice of Hearing and Procedural Order No. 1, the OEB is convening a hearing to consider the motion and is setting out the necessary procedural steps. The OEB is not seeking preliminary submissions on the “threshold” issue described in Rule 43 of the Rules.

To access Hydro One’s motion application and evidence, please select the file number **EB-2022-0071** from the list on the OEB website: www.oeb.ca/notice. You can also phone our Consumer Relations Centre at 1-877-632-2727 with any questions.

The Notice of Hearing and Procedural Order in EB-2022-0071 is being served on all parties from Hydro One’s 2022 IRM, the 2013-14 proceedings regarding the Acquired Utilities, the 2018-2022 rebasing proceeding, and the current 2023 rebasing proceedings.[3] Intervenors in these proceedings are approved as intervenors on this motion proceeding, to the extent they wish to participate and file a submission. Intervenors that were eligible to apply for an award of costs in these proceedings are also eligible to apply for an award of costs in this proceeding.

Being eligible to apply for recovery of costs is not a guarantee of recovery of any costs claimed. Cost awards are made by way of OEB order at the end of this proceeding.

It is necessary to make provision for the following matters related to this proceeding. Further procedural orders may be issued by the OEB.

IT IS THEREFORE ORDERED THAT:

1. Hydro One Networks Inc. is not required to file updated balances for Account 1576 and Account 1592 with its draft rate order in the EB-2021-0033 proceeding.

2. To the extent that Hydro One Networks Inc. has argument in chief in addition to the arguments provided in its Notice of Motion, it shall file these submissions with the OEB and serve it on all parties by **January 31, 2022**.

3. Any written submission by intervenors and OEB staff shall be filed with the OEB and served on Hydro One Networks Inc. and all other parties by **February 14, 2022**.

4. Any reply submission by Hydro One Networks Inc. shall be filed with the OEB by **February 21, 2022**.

[3] EB-2021-0033, EB-2013-0187, EB-2014-0244, EB-2014-0213, EB-2017-0049 and EB-2021-0110

Parties are responsible for ensuring that any documents they file with the OEB, such as applicant and intervenor evidence, interrogatories and responses to interrogatories or any other type of document, **do not include personal information** (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure..

Please quote file number, **EB-2022-0071** for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the OEB's online filing portal.

- Filings should clearly state the sender's name, postal address, telephone number and e-mail address
- Please use the document naming conventions and document submission standards outlined in the Regulatory Electronic Submission System (RESS) Document Guidelines found at the Filing Systems page on the OEB's website
- Parties are encouraged to use RESS. Those who have not yet set up an account, or require assistance using the online filing portal can contact registrar@oeb.ca for assistance

All communications should be directed to the attention of the Registrar at the address below and be received by end of business, 4:45 p.m., on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Kelli Benincasa at Kelli.Benincasa@oeb.ca and OEB Counsel, Michael Millar at michael.millar@oeb.ca.

Email: registrar@oeb.ca
Tel: 1-877-632-2727 (Toll free)

DATED at Toronto, **January 12, 2022**

ONTARIO ENERGY BOARD

Nancy Marconi
Acting Registrar

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2010-0184

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF a motion by the Consumers Council of Canada in relation to section 26.1 of the *Ontario Energy Board Act, 1998* and Ontario Regulation 66/10.

BEFORE: Howard Wetston
Chair

DECISION WITH REASONS

August 5, 2010

THE PROCEEDING

On April 26, 2010, a Notice of Motion was filed by the Consumers Council of Canada ("CCC") regarding the assessments issued by the Ontario Energy Board (the "Board") pursuant to section 26.1 of the *Ontario Energy Board Act, 1998* (the "Act").

On May 11, 2010, the Board issued a Notice of Hearing and Procedural Order No. 1 (the "Notice") in which the Board decided that before determining whether or not it would hear the motion, the Board intended to hear argument on a number of preliminary questions that were set out in the Notice. The preliminary questions set out in the Notice included, but were not limited to, the following:

(a) given Rule 42.02 of the Rules, does CCC have standing to bring the Motion;
(b) does the Board have the authority to cancel the assessments issued under section 26.1 of the Act;
(c) does the Board have the authority to determine whether section 26.1 of the Act (and Ontario Regulation 66/10 made under the Act) are constitutionally valid in the absence of another proceeding (i.e., can the constitutionality of the legislation be the only issue in the proceeding); and
(d) would stating a case to the Divisional Court be a better alternative?

A number of intervenors provided written argument in response to the questions in the Notice. On July 13, 2010, the Board held an oral hearing to hear further argument on the preliminary questions. In their pre-filed materials relating to the preliminary issues, certain intervenors made arguments in favour of staying the assessments resulting from the application of section 26.1 of the Act until the motion to determine whether the assessments were constitutional was heard on its merits. However, no party had brought a formal motion to stay the assessments that was supported by evidence. The Attorney General of Ontario (the "Attorney General") argued in its responding materials that the granting of a stay had not been identified by the Board as one of the preliminary issues to be heard on July 13, 2010, and that the issue should therefore not be heard that day. In the alternative, the Attorney General argued that the test for a stay had not been met and should therefore be denied.

At the hearing on July 13, 2010, the Board determined that it would hear argument on the stay issue. After hearing the arguments and reviewing the pre-filed materials, the Board determined that it was not satisfied with the state of the record regarding the stay issue. As the request for a stay had not been made through a fully supported motion, the Board, through Procedural Order No. 4, afforded parties the opportunity to file additional materials, including evidence to support their request for a stay.

On July 19, 2010, Canadian Manufacturers & Exporters ("CME") filed a notice of motion seeking a stay of the assessments issued by the Board on April 9, 2010 until such time as matters pertaining to the constitutional validity of Ontario Regulation 66/10 (the "Regulation") have been decided on their merits (the "CME Motion"). The CME Motion was opposed by the Attorney General. The CME Motion was argued before the Board on July 26, 2010. Several other intervenors adopted their original submissions from the July 13, 2010 hearing relating to the stay and provided some additional comments in support of CME's Motion. The Board issued a decision and order (without reasons) later that day dismissing the CME Motion. The Board's reasons for that decision and order are included below.

THE SPECIAL PURPOSE CHARGE AND THE ROLE OF THE BOARD

Sections 26.1 and 26.2 of the Act provide for a special purpose charge ("SPC") to be assessed to certain persons with respect to the expenses incurred and expenditures made by the Ministry of Energy and Infrastructure in respect of its energy conservation programs or renewable energy programs.

The Regulation provides the details for the overall amount of the SPC, how the SPC is to be allocated between the persons required to pay the assessments, and how the persons required to pay the SPC assessments may recover the amounts.

The Regulation sets out that the total amount of the SPC is $53,695,310. The Regulation clearly states how the Board is to apportion that amount among the Independent Electricity System Operator (the "IESO") and licensed electricity distributors. In the simplest terms, the Regulation contains a formula, with corresponding definitions, that sets out how the Board is to calculate an amount. The Board then uses that amount in other formulas set out in the Regulation to apportion the SPC among the IESO and licensed electricity distributors. The Board's role is to perform the calculation identified in the Regulation and as such, the Board's role is not discretionary or adjudicative.

Similarly, the manner in which the IESO and licensed electricity distributors may recover the assessments they are required to pay under the Regulation is also set out in the

Regulation. The Board has no discretion in how those amounts are calculated or the mechanism for recovery.

CCC'S STATUS

Submissions were made regarding the issue of standing and more particularly whether or not CCC needed leave to bring the motion. The Attorney General was satisfied that Aubrey LeBlanc had standing to bring the motion. The Attorney General argued, however, that CCC itself did not have standing to bring the motion and should be considered an intervenor. For the purposes of this proceeding, the Board finds that CCC should be considered an intervenor.

THE BOARD'S AUTHORITY TO HEAR THE CONSTITUTIONAL ISSUE

The constitutional issue before the Board is whether the SPC is an unconstitutional indirect tax or a valid regulatory charge. Before hearing the question on its merits, the Board first had to satisfy itself that it had the authority to determine the constitutional question.

Section 19 of the Act provides that the Board has "in all matters within its jurisdiction authority to hear and determine all questions of law and of fact." There was no disagreement among the intervenors that the Board had the jurisdiction to hear the constitutional issue. As stated by the Attorney General, when an administrative tribunal has the explicit or implicit jurisdiction to deicide questions of law arising under a legislative provision, it is presumed that the tribunal also has jurisdiction to decide the constitutional validity of that provision.

The Board agrees that it has the jurisdiction to determine the constitutional issue regarding the SPC.

BOARD HEARING VERSUS A STATED CASE

While there was agreement that the Board has the jurisdiction to hear the constitutional issue, intervenors also acknowledged that the Board has the authority to state a case to the Divisional Court under section 32 of the Act. Most parties argued that the Board should hear the constitutional question rather than state a case to the Divisional Court. Intervenors submitted that the Board should develop the evidentiary record necessary to state a case and that it would be more efficient for the Board to hear the matter. However, the Association of Power Producers of Ontario ("APPrO") and Union Gas Limited ("Union") argued that stating a case to the Divisional Court would be the preferred option, once the evidentiary record was developed by the Board, since the matter would likely ultimately be resolved by the Courts in any event.

The Attorney General argued that the Board should hear the case and determine the questions of fact and law rather than stating a case to the Divisional Court. The Attorney General contended that it would be more expeditious for the Board to determine the entire matter rather than to have an evidentiary hearing before the Board, an argument on the law before the Divisional Court, have the matter referred back to the Board from the Divisional Court, and then have the Board consequently apply the Court's opinion.

The Board agrees with the Attorney General and the other parties that argued that the Board should hear the matter and not state a case to the Divisional Court. The Board finds that it would be more efficient and expeditious for the Board to determine the facts and law with respect to the constitutional question in this matter. The Board will set a date for the filing of the evidence by the Attorney General by procedural order in due course.

STAYING THE ASSESSMENTS

Positions of the Intervenors

In its motion materials, CME argued that the Board has a duty and an obligation to consider the constitutionality of its actions taken in response to the Regulation. By failing to consider the legality of the Regulation prior to issuing the assessments, CME submitted that the Board erred and that it should now stay the assessments pending this consideration. CME's position was that the presumption of constitutional validity does not apply to actions taken by a quasi-judicial tribunal in response to enactments of questionable validity requiring the tribunal to perform particular actions, and cited *R.* v. *Conway*, [2010] S.C.J. No. 22 ("*Conway*") in support of this argument. In particular, counsel argued that the administration of justice is irreparably harmed where a tribunal presumes its own actions are valid prior to assessing their legality.

Although CME argued that the test for a stay established in *RJR-MacDonald Inc.* v. *Canada (Attorney General)*, [1994] 1 S.C.R. 311 ("*RJR-MacDonald*") did not apply to this case, it did submit that irreparable harm would result if the assessments were not stayed. CME argued that any assessments paid by distributors might not be returned by the government if the assessments were ultimately found to be unconstitutional. CME further submitted that even if the assessed amounts were refunded to the distributors, returning the money to individual ratepayers would be problematic, and that distributors might face class action law suits requiring the return of the assessed amounts, including significant legal costs.

Union also argued in favour of a stay, and relied on the three part test for a stay from *RJR-MacDonald*, namely:

(a) is there a serious issue to be tried;
(b) will the moving party suffer irreparable harm prior to the determination of the matter if the stay is refused; and
(c) does the balance of convenience, taking into account the public interest, favour the granting of a stay?

All three branches of the test must be satisfied if a stay is to be granted.

Union argued that the threshold for a serious issue was low and that it was proven in this case.

Union submitted that irreparable harm in the form of class action law suits brought by ratepayers against distributors could result if the assessed amounts are ultimately found to be unconstitutional. Even if the government were to return the assessed amounts to the distributors, such amounts could not be returned on a dollar for dollar basis to the ratepayers from whom the distributors initially recovered the money. A class action law suit could impose serious financial harm on distributors. Union also submitted that distributors may suffer a loss of profits and that the loss of profits would constitute irreparable harm.

Union further argued that the balance of convenience in this case favours ratepayers and distributors over the Province, largely on the basis that, once paid, it would be very difficult to return the amounts either to distributors or to ratepayers.

The request for a stay was also supported by CCC, VECC, and APPrO.

The CME Motion was opposed by the Attorney General. The Attorney General relied on the three-part test in *RJR-MacDonald*. The Attorney General agreed that the threshold for establishing a serious issue is not high but submitted that the moving party cannot succeed on this branch of the test.

The Attorney General argued that even if the Board finds that the serious issue branch of the test has been met, that the CME Motion meets neither the irreparable harm nor the balance of convenience branches of the test.

The meaning of "irreparable" was discussed at paragraph 59 in *RJR-MacDonald*:

> "Irreparable" refers to the nature of the harm suffered rather than its magnitude. It is harm which either cannot be quantified in monetary terms or which cannot be cured, usually because one party cannot collect damages from the other.

The Attorney General argued that any alleged harm that may be suffered if the assessments are ultimately found to be unconstitutional can be quantified in monetary terms because the amount of the assessments is known and that any harm can be remedied. In *Kingstreet Investments Ltd.* v. *New Brunswick (Finance)*, [2007] 1 S.C.R. 3 ("*Kingstreet*"), the Supreme Court held that where the government collects a tax that is found to be unconstitutional, those who paid the tax are entitled to restitution. The Attorney General further observed that irreparable harm must relate to the applicant's own interests, and that here the moving party (CME) was not alleging harm to itself, but rather to distributors. Finally, the Attorney General argued that the courts have already decided in *Canada (Attorney General)* v. *Amnesty International Canada*, [2009] F.C.J. 545, and *Canadian National Railways* v. *Leger*, [2000] F.C.J. 243, that potential legal costs incurred by distributors to defend against class proceedings do not constitute irreparable harm.

The Attorney General argued that the CME Motion also fails the balance of convenience branch of the test because CME must demonstrate that the balance of convenience operates in favour of granting a stay. The Attorney General cited a number of cases which stand for the principle that, in constitutional cases, the balance of convenience is a very low hurdle for governments, and a very high hurdle for applicants. In *RJR-MacDonald*, the Court held:

> In order to overcome the assumed benefit to the public interest

> arising from the continued application of the legislation, the applicant who relies on the public interest must demonstrate that the suspension of the legislation would itself provide a public benefit. (para. 80)

The Attorney General argued that CME cannot satisfy the balance of convenience branch of the test.

The Attorney General submitted that tribunals perform their duties under the presumption that statutes passed by the legislature are constitutionally valid until determined to be otherwise. The Attorney General argued that CME's submission that a tribunal should not act pursuant to legislation until it has considered the constitutional validity of the legislation is incorrect.

Decision

The Board finds that the appropriate test for granting a stay in these circumstances is the three part test identified in *RJR-MacDonald*.

The Board accepts that there is a serious issue to be tried in this case. However, it is not satisfied that irreparable harm will result if a stay is not granted, nor is it satisfied that the balance of convenience rests in favour of CME or the intervenors seeking the stay.

The potential harm identified in support of the motion is not irreparable. The harm identified is monetary and quantifiable; indeed, the total amount of the assessments is already known. The *Kingstreet* decision determined that, at a minimum, restitution would be available if the assessments are ultimately found to be unconstitutional. In the event that the assessments were returned to distributors, although a dollar for dollar refund to each ratepayer that paid their share of the original assessment would be impractical, the Board would have the ability to return these amounts to ratepayers by requiring the refunded amounts to be placed in a variance account or a deferral account. This amount could then be cleared through rates and act as an offset to each distributor's revenue requirement.

The Board also agrees with the Attorney General that the possibility of a class action law suit does not constitute irreparable harm.

CME argued that the Board should stay the assessment based on *Conway*. CME submitted that the Board had an obligation and a duty to determine the constitutional validity of the legislation and that that obligation and duty constituted a threshold legal requirement that the Board had to take into account when issuing the assessments. CME submitted that the assessments must be set aside until the threshold constitutional question had been answered. The Board is not persuaded by this argument. *Conway* deals with a tribunal's authority to determine constitutional questions; it does not deal with matters of interlocutory relief or stays. The Board does not find that the *Conway* case provides authority for the Board to stay the assessments.

The Board does not agree with CME's argument that the administration of justice would be irreparably harmed if the Board presumes the actions it took pursuant to the Regulation are legal. There is no basis for a finding that the presumption of legislative validity should not apply in this case.

The Board also does not accept Union's argument that any alleged loss of profits to the distributors would amount to irreparable harm to distributors. The amounts the electricity distributors pay as assessments will be recovered from consumers within a twelve month period. The variance account which has been established by the Board to record this recovery will ensure that there is no over or under recovery. In addition, the variance account allows distributors to recover their carrying charges for the assessed amounts.

The Board accepts the Attorney General's arguments with respect to the balance of convenience. CME has failed to meet the high threshold of establishing that the balance of convenience weighs in its favour.

As previously stated, in order to overcome the assumed benefit to the public interest from the continued application of the legislation, it must be demonstrated that the suspension of the legislation would itself provide a public benefit. The intervenors that argued for a stay suggested that the public interest to be gained by staying the legislation and Regulation is that electricity distributors and the IESO, and their consumers, will not have to pay the costs of the SPC.

Arguments that suggest that the suspension of the assessments would amount to a public interest which outweighs the public interest in the continued application of the legislation are not supportable. These arguments relate only to an economic and personal interest in not paying the SPC. The Supreme Court addressed similar arguments in *RJR-MacDonald* relating to the increased price of tobacco products. The Supreme Court stated that "such an increase is not likely to be excessive and is purely economic in nature. Therefore any public interest in maintaining the current price of tobacco products cannot carry much weight." (*RJR-MacDonald* at para. 93)

The Board agrees that there is a high threshold for applicants to overcome in constitutional cases, and the parties seeking the stay have not provided clear evidence to meet this threshold.

COSTS

The Notice stated that the Board did not intend to grant cost awards in this proceeding. The Board had decided that no costs were warranted as the original Notice limited the extent of participation in the hearing to four parties, namely CCC, the Attorneys General of Ontario and Canada, and the Ministry of Energy and Infrastructure. However, as the hearing progressed, the Board allowed further participation in the hearing and a number of other parties intervened in the proceeding. Given the expanded participation in the proceeding, and the value the Board sees in having the expanded participation, the Board will allow for costs. Costs were requested by a number of intervenors, namely CCC, CME, VECC, and APPrO.

Under the circumstances, the Board will not rely on section 30 of the Act for costs. Distributors and the IESO should not be entirely responsible for paying the costs of this proceeding. The electricity distributors and the IESO are required to pay the SPC by virtue of the Regulation; this was not within their control. The Board also notes that the assessments may be extended to the natural gas sector in the future. Section 26.1 of the Act contemplates gas distributors being included in the assessments. Therefore, natural gas utilities and customers will also benefit from having the constitutional issue decided.

The Board has therefore determined that it would be more efficient for the Board to provide funding to groups representing the interests of customers that may be affected by this proceeding through section 26 of the Act. The rates for legal counsel's hourly fees will be determined in accordance with the Tariff in the Board's Practice Direction on Cost Awards (the "Practice Direction") and the Board will follow the principles set out in section 3 of the Practice Direction when determining eligibility for costs and the principles in section 5 of the

Practice Direction amount of the costs it will allow the intervenors to recover.

Based on section 3 of the Practice Direction, the Board finds that CCC, CME, and VECC are eligible to apply for their costs of participating in this proceeding.

APPrO has also requested costs in this proceeding. APPrO represents the interests of power producers who are not eligible under the Practice Direction unless they are a customer of the applicant or there are special circumstances. APPrO is not a customer of the "applicant" in this proceeding because the "applicant" in this proceeding is Aubrey LeBlanc/CCC (or for the motion for the stay, CME) and APPrO is not a customer of those parties. Therefore, the Board must consider whether there are special circumstances to warrant granting cost eligibility to APPrO.

APPrO has been granted intervenor status and of course may participate in this proceeding. While it is true that generators will pay the SPC assessments as load customers, is that sufficient to amount to special circumstances in this proceeding? The Board is of the opinion that it is not. APPrO's position as a consumer (as load) in this proceeding is not unique compared to the other consumer groups. APPrO would also not appear to have any greater expertise with respect to the constitutional issue being determined by the Board in this proceeding than any other consumer group. The Board therefore finds there are no special circumstances to warrant granting APPrO costs in this proceeding. This is in no way a comment on the contributions made by APPrO, to date, in this matter.

DATED at Toronto, August 5, 2010

ONTARIO ENERGY BOARD

Original signed by

Howard Wetston
Chair

Practice and Procedure Before Administrative Tribunals § 16:40

Practice and Procedure Before Administrative Tribunals
Lorne Sossin, Robert W. Macaulay, James L.H. Sprague

Chapter 16. The Conduct of the Hearing: Powers and Procedures

V. Interventions; Interrogatories

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§ 16:40. Interventions

Interveners are generally individuals or groups who do not meet the criteria to be a party but who still have a sufficient interest, or some expertise or view which the agency feels will benefit the proceeding to have represented. As the Supreme Court of Canada commented in the *Canadian Council of Churches v. Canada* [1] "[T]he views of the public litigant who cannot obtain standing need not be lost. Public interest organizations are, as they should be, frequently granted intervenor status. *The views and submissions of intervenors on issues of public importance frequently provide great assistance to the courts."* [emphasis added.] [2]

A statute may expressly give an agency the authority to grant intervener status to a person or group. [3] Otherwise an agency's authority to grant intervener status flows implicitly from the power to conduct a hearing or to hold an inquiry. [4] It appears that, at least in the case of a public officer, in order for an agency to grant such status the person seeking intervenor status must have the ability himself to receive the grant. [5]

There is no common law *right* to be an intervenor. Statute may, of course, grant such a right but in the absence of such a statutory provision, intervenors are added at the discretion of the agency. Furthermore, unlike a party, who is given certain rights by natural justice and fairness, the extent of an intervenor's participation is fixed by the agency (subject to statutory direction, of course). The degree of participation will be determined by the extent the agency feels the intervener's participation will assist it in its mandate. [6]

In considering a request for intervention the agency should take into account the perceived value that might brought to the table by that participation against any harm or other downside that granting the application might cause. [7] Sometimes two or more individuals or groups may bring before the agency essentially the same expertise or views. In that case the agency may require that they pool their resources and appear through a single spokesman. [8] However, it must be remembered that an intervenor is there to bring a view or an expertise before the agency which will be useful in determining the matter which is before the agency. If the person seeking intervenor status is not bringing anything of potential use to the agency, or is simply repeating which will already be brought or could be brought to the agency by the other parties, the agency should not grant intervenor status out of concerns respecting the public (and the parties') interest in efficient and expeditious proceedings. [9]

An intervenor should not be given leave to speak to questions which are not raised by the underlying proceeding. [10]

The flip side of this coin is that, just as the role of intervenors is limited to bringing a view or expertise to the agency which would not otherwise be available to it the agency cannot at the end of the day treat the intervenor as a party capable of being made subject to the ultimate order or decision which is before the agency. In illustration, see the decision of the Quebec Court of Appeal in Collège d'enseignement general & professionnel A c. Flynn, 2012 CarswellQue 1841, 2012 QCCA 441. In that case the Quebec Court of Appeal noted that an intervenor in a harassment grievance could not be made the target of an order issued by the arbitrator as an outcome of the grievance. In the case in point a grievance had been brought against a college by an

> [46] They should not act in this way. They should stay in their proper place. Their place is not in the public square amongst the partisans and the politicians, participating in the fray. Instead, their place is inside their courthouses, hearing each side, weighing and assessing the admissible evidence and discerning and applying the relevant legal doctrine, all in a rational, open-minded and neutral way, both in appearance and actual fact.

In the result, Stratas J.A. dismissed all of the motions to intervene.

Footnotes

1 Canadian Council of Churches v. Canada (1992), 132 N.R. 241 (S.C.C.).

2 Although it involved intervention in a judicial review proceeding, for an instance where a third party was added as an intervenor see Lockerbie & Hole Industrial Inc. v. Alberta (Director, Human Rights & Citizenship Commission), 2010 CarswellAlta 1031, 2010 ABCA 184 (Alta. C.A.). In that case two associations of employers involved in the construction section were granted leave to intervene in a proceeding before the Alberta Court of Appeal which involved the meaning and application of the term “employer” in the Alberta Human Rights Act. The associations did not seek to provide new evidence or facts but only sought only to make legal submissions. Affidavits filed by the associations indicated how a judicial ruling respecting the operation of the Act would have significant implications respecting their operations. In granting intervenor status the Court of Appeal noted that: “The law in this jurisdiction is well established—”an intervention may be allowed where the proposed intervener is specially affected by the decision facing the Court or the proposed intervener has some special expertise or insight to bring to bear on the issues facing the court”.

3 See, for example, section 33 of British Columbia's *Administrative Tribunals Act*, S.B.C. 2004, c. 45.

4 Nfld. Telephone Co. v. TAS Communications Systems Ltd. (1987), 45 D.L.R. (4th) 570 (S.C.C.).

5 In Nfld. Telephone Co. v. TAS Communications Systems Ltd. (1987), 45 D.L.R. (4th) 570 (S.C.C.) the Supreme Court held that the Newfoundland Board of Commissioners of Public Utilities could not grant intervenor standing to the federal Director of Investigation and Research as the federal government had not given that officer the mandate to appear before provincial agencies. The Court held that “Whatever scope may be reasonably assigned to the implied power or discretion of the board to permit intervention, it cannot have been intended that the board should have authority to permit intervention by a public officer in his official capacity if the officer has been denied the necessary authority to intervene by his governing statute …. To permit intervention where a public officer is shown to lack the necessary authority to intervene would be to permit him to exceed his authority and thus would be contrary to a fundamental principle of public law.” The Court had earlier held that the official required some statutory authority to intervene in the capacity of his office as that intervention would amount to “an assertion, in an adjudicative context, of the authority and expertise of a public official. In such a case, a public officer puts the weight of his opinion and knowledge acquired in the exercise of his official duties, on the adjudicative scales. He extends, on his own initiative, the effective reach and influence of his office and authority with potential direct legal effect.” For a similar decision see City of Edmonton v. Canadian Radio-television and Telecommunications Commission, [1983] 1 F.C. 358 (C.A.).

6 See for example, the description of the role of intervenors before the National Energy Board in § 5.5(d)(iv) and the Ontario Energy Board in § 5.4.

In Collège d'enseignement general & professionnel A c. Flynn, 2012 CarswellQue 1841, 2012 QCCA 441 the Quebec Court of Appeal held that an arbitrator, having granted a teacher the right to intervene in a harassment grievance by an employee against a college (arising out of the teacher's actions) did not breach natural justice in limiting the intervenor teacher's ability to cross-examine.

> 22 A return to basics seems indicated. Respondent N. is *not* a party to the grievance process. The union and the employer are the parties to it. The arbitrator afforded N. ample opportunity to justify and/or explain the events described by complainant. It is the employer who has an obligation to provide a harassment free work environment. If it fails to do so, an arbitrator will decide what is to be done about

> it. The arbitrator must act fairly by listening to the testimony of all concerned and, in this case, did so. She even granted respondent N. a right to cross-examine the complainant on those topics where his position was not endorsed by his union or by the employer, or diverged from their position. There is certainly nothing unfair in such a decision.

7 In Tsleil-Waututh Nation v. Canada (Attorney General), 2017 CarswellNat 4093, 2017 FCA 174 (Fed. C.A.) the Federal Court of Appeal noted that in considering an application for intervenor status in proceedings before the Court the Federal Court must “take care to ensure that procedural and substantive unfairness is not caused to the parties directly affected by the proceedings: the existing applicants and respondents.” (That comment was made in the context of an application for intervenor status by the Attorney General of B.C. which was made long after the deadline for applications set by the Court and the Court's already having dealt with the resulting applications for intervenor status.).

8 Of relevance to this point is the caution sounded by Lord Hoffman in the British House of Lords decision in In Re E (a child), [2008] UKHL 66 (H.L.) respecting interventions in proceedings before the House of Lords. Those comments are also applicable to proceedings before Canadian agencies.

“It may however be of some assistance in future cases if I comment on the intervention by the Northern Ireland Human Rights Commission. In recent years the House has frequently been assisted by the submissions of statutory and non-governmental organizations on questions of general public importance. Leave is given to such to intervene and make submissions, usually in writing but sometimes orally from the bar, in the expectation that their fund of knowledge or particular point of view will enable them to provide the House with a more rounded picture than it would otherwise obtain. The House is grateful to such for their help.

An intervention is however of no assistance if it merely repeats points which the appellant or respondent has already made. An intervener will have had sight of their printed cases and, if it has nothing to add, should not add anything. It is not the role of an intervener to be an additional counsel for one of the parties. This is particularly important in the case of an oral intervention. I am bound to say that in this appeal the oral submissions on behalf of the NIHRC only repeated in rather more emphatic terms the points which had already been quite adequately argued by counsel for the appellant. In future, I hope that interveners will avoid unnecessarily taking up the time of the House in this way.”

9 In Canada (Prime Minister) v. Khadr, 2009 CarswellNat 1637, 2009 FCA 191 (Fed. C.A.) (which dealt with efforts to repatriate Omar Khadr from Guantanamo Bay and the American military process) Amnesty International sought, and was refused intervenor status before the Federal Court of Appeal. The Court applied the test set out in C.U.P.E. v. Canadian Airlines International Ltd., [2000] F.C.J. No. 220 (Fed. C.A.). That test set out the following factors for consideration:

1) Is the proposed intervener directly affected by the outcome?

2) Does there exist a justiciable issue and a veritable public interest?

3) Is there an apparent lack of any other reasonable or efficient means to submit the question of the Court?

4) Is the position of the proposed intervener adequately defended by one of the parties to the case?

5) Are the interests of justice better served by the intervention of the proposed third party?

6) Can the Court hear and decide the case on its merits without the proposed intervener?

Of those, the Court of Appeal stated that it considered particularly whether:

- the position of the proposed intervener is adequately defended by one of the parties to the case;
- the interests of justice are better served by the intervention of the proposed third party;
- the Court can hear and decide the cause on its merits without the proposed intervener.

Practice and Procedure Before Administrative Tribunals § 13:1

Practice and Procedure Before Administrative Tribunals
Lorne Sossin, Robert W. Macaulay, James L.H. Sprague

Chapter 13. The Duty of Fairness and Powers of an Agency to Control its Own Procedure

I. In General

§ 13:1. Mastery Over Their Own Procedure

You cannot be either a successful administrative agency or practitioner unless you grasp the essential fact that, subject to certain limitations which will be discussed below, an administrative agency is "master of its own procedure", [1] Some statutes expressly grant the agency a general power over procedure. [2] Even in the absence of an express grant of authority to that effect, the authority is implied in the grant of the agency's mandate. The authority to develop the necessary procedure to effect a mandate is implicit in the grant of that mandate. [3] What this means is that an agency is free to develop its procedures as required in order to accomplish its particular purposes. [4] In this text I shall refer to this implied authority as the agency's common law power over procedure.

In determining its procedures an agency is not bound by the manners and traditions of the courts. And, while it may be prudent, and even fruitful, to look at judicial procedure in the formulation of agency process, to do so without understanding the strengths, weaknesses and purposes of both is to invite problems. The uncritical adoption of judicial mores leads to unsuitable, and (I would argue) unsuccessful agency operations. This applies as much to the courts when they judge agency procedures in terms of judicial process, as it does to agencies or practitioners before them. I submit that in developing or urging a particular procedure upon an agency it is simply not sufficient to copy judicial practice in the expectation that this must be the best there is.

Very simply put, this is because agencies do not serve the same function as do courts. I doubt very much that anyone would like major surgery conducted upon themselves by doctors dedicated to do so in accordance with the very best judicial process. Even when the agency's function appears very close to a court function, disciplinary hearings for example, I suggest that it is incorrect to blindly pattern the agency essentially upon judicial process. After all there must be a reason the function has been mandated to an administrative agency and not to a court. [5]

> The procedural format adopted by the administrative tribunal must adhere to the provisions of the parent statute of the Board. The process of interpreting and applying statutory policy will be the dominant influence in the workings of such an administrative tribunal. Where the Board proceeds in the discharge of its mandate to determine the rights of the contending parties before it on the traditional basis wherein the onus falls upon the contender to introduce the facts and submissions upon which he will rely, the Board technique will take on something of the appearance of a traditional Court. Where, on the other hand, the Board, by its legislative mandate or the nature of the subject-matter assigned to its administration, is more concerned with community interests at large, and with technical policy aspects of a specialized subject, one cannot expect the tribunal to function in the manner of the traditional Court. This is particularly so where Board membership is drawn partly or entirely from persons experienced or trained in the sector of activity consigned to the administrative supervision of the Board. Again where the Board in its statutory role takes on the complexion of a department of the executive branch of Government concerned with the execution of a policy laid down in broad concept by the Legislature, and where the Board has the delegated authority to issue regulations or has a broad discretionary power to license persons or activities, the trappings and habits of the traditional Courts have long ago been discarded. [6]

(e.g. national security) the goals of the state (i.e. the agency) come first. The party will have to settle for less—the best of the lesser procedures which will not imperil the agency's goal.

Footnotes

1 Prassad v. Canada (Minister of Employment & Immigration), [1989] 1 S.C.R. 560, 36 Admin. L.R. 72, 57 D.L.R. (4th) 663; T.A. Miller Ltd. v. Minister of Housing & Local Government, [1968] 1 W.L.R. 992 (C.A.); Re Cedarvale Tree Services Ltd. v. L.I.U.N.A., Local 183, [1971] 3 O.R. 832, 22 D.L.R. (3d) 40 (C.A.); Therrien (Re), 2001 CarswellQue 1013, 155 C.C.C. (3d) 1, 43 C.R. (5th) 1, 270 N.R. 1 (S.C.C.).

Thus, in Commission des services financiers et des services aux consommateurs c. Emond et autre, 2017 CarswellNB 248, 2017 CarswellNB 249, 2017 NBCA 28 (N.B.C.A.) the New Brunswick Court of Appeal held that where the Tribunal of the New Brunswick Financial Consumer Services Commission was concerned that there may have been undue delay in pursuing a matter before it was reasonable for the agency to order that the issue of delay be argued as a preliminary matter. The Court of Appeal stated that agencies “have an inherent right to control their own processes, subject to legislative constraints, and the principles of procedural fairness.” In the view of the Court of Appeal the Tribunal's decision to hear submissions on the question of delay first before proceeding to a full hearing on the merits “was an exercise of discretionary authority in the interests of time and financial economies.”

2 See for example s. 39(1)(d) of the *Canadian International Trade Tribunal Act*, S.C., c. C-18.3, “The Tribunal may, after consultation with the Minister and with the approval of the Governor in Council, make rules, not inconsistent with this or any other Act of Parliament … (d) generally, governing the proceedings, practice and procedures of the Tribunal.”

3 Re Clement (1919), 27 B.C.R. 361, 48 D.L.R. 237 (C.A.).

In Commission des services financiers et des services aux consommateurs c. Emond et autre, 2017 CarswellNB 248, 2017 NBCA 28 (N.B.C.A.) the New Brunswick Court of Appeal stated that agencies have an inherent right to control their own processes subject to legislative constraints and the principles of procedural fairness.

> 16 As the Supreme Court concluded in *Dunsmuir*, a reasonableness standard of review will generally apply “[w]here the question is one of fact, discretion or policy” or “where the legal and factual issues are intertwined with and cannot be readily separated” (para. 53). In *Barton v. WorkSafe NB*, 2017 NBCA 13, [2017] N.B.J. No. 40 (QL), Drapeau C.J.N.B. reiterated that Tribunals have an inherent right to control their own processes, subject to legislative constraints, and the principles of procedural fairness. He observed that in *Prassad v. Canada (Minister of Employment and Immigration)*, [1989] 1 S.C.R. 560, [1989] S.C.J. No. 25 (QL), the Supreme Court concluded:
>
> > […] We are dealing here with the powers of an administrative tribunal in relation to its procedures. As a general rule, these tribunals are considered to be masters in their own house. In the absence of specific rules laid down by statute or regulation, they control their own procedures subject to the proviso that they comply with the rules of fairness and, where they exercise judicial or quasi-judicial functions, the rules of natural justice. Adjournment of their proceedings is very much in their discretion. [para. 16]

4 Nicholson v. Haldimand-Norfolk (Regional Municipality) Comm. of Police, [1979] 1 S.C.R. 311, 78 C.L.L.C. 14,181, 88 D.L.R. (3d) 671, 23 N.R. 410; Selvarajan v. Race Relations Board, [1976] 1 All E.R. 12 (C.A.).

5 In Salem v. Metropolitan Toronto (Licensing Commission) (1993), 63 O.A.C. 198 (Div. Ct.) the Ontario Divisional Court held that the Metropolitan Licensing Commission (Toronto) was not a court and was not required to follow the strict formalities of court procedure. Nonetheless, tis procedures had to at least ensure 1. that licensees are given a clear statement of the allegations against them and the basis on which liability is sought to be established; 2. that proceedings are conducted with enough order and structure to ensure that it is clear who has to prove what; 3. that respondents have a fair and orderly opportunity to call evidence and make submissions in respect of both liability and penalty; and 4. that adequate reasons are given for the decisions of the tribunal.

§2.05 COMMON LAW PROCEDURAL REQUIREMENTS: THE DUTY TO BE FAIR

Administrative Law in Canada, 7th Ed.

Sara Blake

PART I PROCEEDINGS BEFORE THE TRIBUNAL

Chapter 2 TRIBUNAL PROCEDURE

§2.05 COMMON LAW PROCEDURAL REQUIREMENTS: THE DUTY TO BE FAIR

In the absence of prescribed procedural rules, the courts require that a statutory decision that affects the rights of an individual person be made following fair procedures.[1] This requirement is called the "doctrine of fairness" or the "duty to act fairly".[2]

At a minimum, the duty to act fairly requires that, before a decision adverse to a person's interests is made, the person should be told the case to be met and be given an opportunity to respond.[3] The purpose is twofold. First, it gives the person to be affected an opportunity to influence the decision. Second, the information received from that person may assist the decision maker to make a rational and informed decision.[4] A person is more willing to accept an adverse decision if the process has been fair.

The right to be heard is not a right to the most advantageous procedure[5] nor a right to have one's views accepted[6] nor a right to be granted the remedy sought.[7] It is only a right to have one's views heard and considered by the decision maker.

A variety of procedural options are available to meet the duty to be fair. What is "fair" in a given case depends on the circumstances.[8] The flexible nature of the duty of fairness recognizes that meaningful participation can occur in different ways in different situations.[9] Sometimes, all that is required is that the person be advised verbally of the gist of the proposed decision and the reasons for it and be permitted to respond verbally.[10] In some cases written notice and an opportunity to make written submissions will suffice. Written submissions may take many forms including completion of a questionnaire,[11] a letter stating one's position, an exchange of correspondence in which the issues are discussed[12] or a formal application supported by documentary evidence and reports of experts. Sometimes a person cannot adequately answer the case without an oral hearing, which may be conducted in a variety of ways. It may be an informal interview with an agent of the decision maker, a round table discussion with the tribunal[13] or a formal proceeding similar to a civil trial or an inquisitorial process. A party may be entitled to see documents relied on by the decision maker and to cross-examine witnesses. Sometimes a decision maker may refer the fact-finding process to others for investigation and report. The main consideration in choosing the appropriate procedure is whether the procedure gives the persons affected a fair opportunity to be heard.

The same procedure is not expected of all tribunals. There is great variety in the types of tribunals and in the types of decisions made by them. The concept of procedural fairness is not a fixed concept. It varies with the context and the interests at stake.[14] "At the heart of this analysis is whether, considering all the circumstances, those whose interests were affected had a meaningful opportunity to present their case fully and fairly." The Supreme Court of Canada has identified the following five factors to be considered in determining what is appropriate.[15]

procedural straitjacket. As long as the procedure adopted by a tribunal treats those who come before it fairly, a court will not intervene.[99]

Costs and efficiency are relevant factors when determining fair procedure. Tribunals that process a high volume of cases may have production targets.[100] They may screen out complaints that lack sufficient evidentiary basis to proceed to a hearing,[101] provided they have statutory authority.[102] In an individual case, the benefits of a procedure may be weighed against its costs.[103] There is a public interest in containing administrative costs and in expeditious decision making. A tribunal may manage a case so as to make the parties focus on the essential issues[104] or it may conduct a hearing where none is required if it believes this is necessary to make a decision in a difficult case.[105] A tribunal may process applications on a "first come, first served" basis.[106] A tribunal may process many similar cases by first adjudicating a "test case" to establish an analytical approach and findings of general facts to be considered by, but not binding on, subsequent panels provided the parties in later cases have a right to dispute the analysis and findings.[107]

A requirement to hold a hearing does not mandate the adversarial process except where required by statute.[108] A tribunal may choose an adversarial or an inquisitorial process or something in-between. An inquisitorial process may be appropriate to process efficiently and fairly a high volume of cases in which parties are often unrepresented, and may be used even if they are represented.[109] If the issue to be decided turns on expert evidence, the tribunal may restrict the evidence to that of the experts and allow the experts to question each other.[110]

Footnote(s)

1 *Martineau v. Matsqui Institution*, [1979] S.C.J. No. 121.

2 It has been variously expressed as "the right to be heard", "the rules of natural justice", "the duty to act judicially" and "*audi alterem partem*" (the duty to hear both sides).

3 *Nicholson v. Haldimand-Norfolk (Regional) Police Commissioners*, [1978] S.C.J. No. 88.

4 *Gill v. Canada (Deputy Commissioner Correctional Service)*, [1989] F.C.J. No. 70 (F.C.A.); *Haghighi v. Canada (Minister of Citizenship and Immigration)*, [2000] F.C.J. No. 854 (F.C.A.).

5 *Ironside v. Alberta (Securities Commission)*, [2009] A.J. No. 376 at para. 107 (Alta. C.A.).

6 *Papin-Shein c. Cytrynbaum*, [2008] J.Q. no 12176 (Que. C.A.); *Nova Scotia (Attorney General) v. Ultramar Canada Inc.*, [1995] F.C.J. No. 1160 at para. 52 (F.C.T.D.).

7 *Enterlake Air Services Ltd. v. Bissett Air Services Ltd.*, [1991] M.J. No. 382 (Man. Q.B.).

8 *Canada (Attorney General) v. Mavi*, [2011] S.C.J. No. 30.

9 *Baker v. Canada (Minister of Citizenship and Immigration)*, [1999] S.C.J. No. 39 at para. 32.

10 *Sexsmith v. Canada (Attorney General)*, [2021] F.C.J. No. 547 (F.C.A.); *B. (K.) (Litigation guardian of) v. Toronto District School Board*, [2008] O.J. No. 475 (Ont. Div. Ct.).

11 *Cannella v. Toronto Transit Commission*, [1999] O.J. No. 2282 (Ont. Div. Ct.).

12 *McLeod v. Alberta Securities Commission*, [2006] A.J. No. 939 at para. 39 (Alta. C.A.), leave to appeal refused [2006] S.C.C.A. No. 380.

13 Round table discussion met duty of fairness: *Atlantic Collection Agency Ltd. v. Nova Scotia (Service Nova Scotia and Municipal Relations)*, [2006] N.S.J. No. 204 (N.S.S.C.); did not: *Kelly v. New Brunswick (Provincial Planning Appeal Board)*, [1984] N.B.J. No. 291 (N.B.Q.B.).

14 *Chiarelli v. Canada (Minister of Employment and Immigration)*, [1992] S.C.J. No. 27 at paras. 45-46.

15 *Baker v. Canada (Minister of Citizenship and Immigration)*, [1999] S.C.J. No. 39 at paras. 21-28, 30.

2.3 CONTINUUM OF PROCEDURAL PROTECTION

Canadian Administrative Law, 3rd Ed.

Guy Régimbald

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Chapter VI PROCEDURAL FAIRNESS/*AUDI ALTERAM PARTEM*

2. CONTENT OF PROCEDURAL FAIRNESS

2.3 CONTINUUM OF PROCEDURAL PROTECTION

Once it has been determined that procedural fairness does apply, the determination of the exact content of procedural fairness remains elusive. The content of any procedural protection will depend on a host of factors, including the nature of the decision-making involved. Given the diversity of administrative action, the requirements to comply with procedural fairness can vary ranging from the full panoply of procedural justice comparable to normal court procedure, to the right simply to be notified and be allowed to defend one's case appropriately.[1]

The content of fair procedures is flexible, involving a continuum of procedural protections. It ranges from mere notice or consultation at the lower end, upwards through an entitlement to make written and oral representations, to a complete judicial procedure similar to other judicial hearings at the other extreme. What is required in any particular case is impossible to define in abstract terms.[2] In *Russell v. Duke of Norfolk*,[3] Lord Tucker opined that: "whatever standard is adopted, one essential is that the person concerned should have a reasonable opportunity of presenting his case."[4] In *R. v. Secretary of State for the Home Department, ex parte Doody*,[5] Lord Mustill held that: "the principles of fairness are not to be applied by rote identically in every situation. What fairness demands is dependent on the context of the decision, and this is to be taken into account in all its aspects."[6] Closer to home, in *Nicholson*, it was held that as the decision-making function approaches the legislative end of the spectrum, the decision maker's procedural obligations decrease.

Within the confines of procedural fairness, the common law affords administrative decision makers significant autonomy in formulating the required procedural content of their decision-making. The content will thus vary from agency to agency and will differ depending on the circumstances of each case.[7] In *Homex Realty and Development Co. v. Wyoming (Village)*,[8] Dickson J., as he then was, opined in dissent that:

> Above all, flexibility is required in this analysis. There is, as it were, a spectrum. A purely ministerial decision, on broad grounds of public policy, will typically afford the individual little or no procedural protection … On the other hand, a function that approaches the judicial end of the spectrum will entail substantial procedural safe-guards, particularly when personal or property rights are targeted, directly, adversely and specifically.[9]

This balance must be done according to the protection needed by the individual, but must also consider the societal need for effective decision-making. The objective is to reach the appropriate balance between an adequate procedure which will allow the government to operate while at the same time protect the interests of the individual. In balancing those elements, courts must take into account the importance of the interest of the individual at stake as compared with that of the state.[10]

Although the procedural content of the duty to act fairly is variable, the courts have sometimes concluded that, at a minimum, it requires that parties to a controversy be given a fair opportunity to correct or contradict any relevant statement prejudicial to their view.[11] Decision makers that are subject to a duty of fairness must give sufficient notice of the hearing and its scope to allow the parties to benefit from their right to be heard. Therefore, affected parties must be given sufficient knowledge of the arguments and evidence that weigh against their interests to enable them to participate in the process in a meaningful way.[12]

As discussed in *Syndicat des employés de production du Québec et de l'Acadie v. Canada (Canadian Human Rights Commission)*:

> Both the rules of natural justice and the duty of fairness are variable standards. Their content will depend on the circumstances of the case, the statutory provisions and the nature of the matter to be decided. The distinction between them therefore becomes blurred as one approaches the lower end of the scale of judicial or quasi-judicial tribunals and the high end of the scale with respect to administrative or executive tribunals. Accordingly, the content of the rules to be followed by a tribunal is now not determined by attempting to classify them as judicial, quasi-judicial, administrative or executive. Instead, the court decides the content of these rules by reference to all the circumstances under which the tribunal operates. In *Martineau v. Matsqui Institution Disciplinary Board*, [1980] 1 S.C.R. 602, at p. 629, Dickson J. (as he then was) stated:
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>> In general, courts ought not to seek to distinguish between the two concepts, for the drawing of a distinction between a duty to act fairly, and a duty to act in accordance with the rules of natural justice, yields an unwieldy conceptual framework.[13]

Footnote(s)

1 See *Syndicat des employés de production du Québec et de l'Acadie v. Canada (Human Rights Commission)*, [1989] S.C.J. No. 103, [1989] 2 S.C.R. 879 at 895 (S.C.C.).

2 S.A. De Smith, H. Woolf & J.L. Jowell, *Principles of Judicial Review*, 5th ed. (London: Sweet & Maxwell, 1995) at 311.

3 *Russell v. Duke of Norfolk*, [1949] 1 All E.R. 109.

4 *Russell v. Duke of Norfolk*, [1949] 1 All E.R. 109 at 118.

5 *R. v. Secretary of State for the Home Department, ex parte Doody*, [1994] 1 A.C. 531.

6 *R. v. Secretary of State for the Home Department, ex parte Doody*, [1994] 1 A.C. 531 at 560.

7 See *Martineau v. Matsqui Institution Disciplinary Board (No. 2)*, [1979] S.C.J. No. 121, [1980] 1 S.C.R. 602 (S.C.C.); *Prassad v. Canada (Minister of Employment and Immigration)*, [1989] S.C.J. No. 25, [1989] 1 S.C.R. 560 (S.C.C.); R.A. Macdonald, "Judicial Review and Procedural Fairness in Administrative Law: 1" (1980) 25 McGill L.J. 520 at 546; Grey, "The Duty to Act Fairly After Nicholson" (1980) 25 McGill L.J. 598 pt. III at 603-604.

8 *Homex Realty and Development Co. v. Wyoming (Village)*, [1980] S.C.J. No. 109, [1980] 2 S.C.R. 1011 (S.C.C.).

9 *Homex Realty and Development Co. v. Wyoming (Village)*, [1980] S.C.J. No. 109, [1980] 2 S.C.R. 1011 at 1051 (S.C.C.).

10 *IWA, Local 269 v. Consolidated-Bathurst Packaging Ltd.*, [1990] S.C.J. No. 20, [1990] 1 S.C.R. 282 at 305 (S.C.C.); *Canada (Minister of Employment and Immigration) v. Chiarelli*, [1992] S.C.J. No. 27, [1992] 1 S.C.R. 711 (S.C.C.); *Thomson Newspapers Co. v. Canada (Attorney General)*, [1998] S.C.J. No. 44, [1998] 1 S.C.R. 877 (S.C.C.).

11 *Board of Education v. Rice*, [1911] A.C. 179 at 182 (H.L.).

12 *Dasent v. Canada (Minister of Citizenship & Immigration)*, [1994] F.C.J. No. 1902, [1995] 1 F.C. 720 (F.C.T.D.); *Canada (Attorney General) v. Mavi*, [2011] S.C.J. No. 30, 2011 SCC 30, [2011] 2 S.C.R. 504 (S.C.C.).

13 *Syndicat des employés de production du Québec et de l'Acadie v. Canada (Human Rights Commission)*, [1989] S.C.J. No. 103, [1989] 2 S.C.R. 879 at 895-96 (S.C.C.); see also *Pearlman v. Manitoba Law Society Judicial Committee*, [1991] S.C.J. No. 66, [1991] 2 S.C.R. 869 at 886 (S.C.C.); *Singh v. Canada (Minister of Employment and Immigration)*, [1985] S.C.J. No. 11, [1985] 1 S.C.R. 177 at 233 (S.C.C.); *Old St. Boniface Residents Assn. Inc. v. Winnipeg (City)*, [1990] S.C.J. No. 137, [1990] 3 S.C.R. 1170 at 1191 (S.C.C.).

Injunctions and Specific Performance § 1:21

Injunctions and Specific Performance
Robert J. Sharpe

Part I. Injunctions

Chapter 1. General Principles

VI. Delay

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§ 1:21. Introduction

A plaintiff, once entitled to an injunction or specific performance, may lose that right on account of delay in asserting the claim. [1] Because the principles governing the treatment of delay are the same whether the remedy sought is specific performance or an injunction, it is convenient to discuss in one place the matter of delay as it affects both remedies. The treatment of delay as a factor determining the availability of specific relief is characteristic of most equitable doctrines: the courts apply general principles rather than specific rules, leaving wide scope for discretion in particular cases.

Consideration of delay is an aspect of the more general principle which takes into account the injustice of awarding relief against a party who will be prejudiced on account of a change of position related to acts or omissions of the party seeking relief. [2]

Delay in asserting one's rights may, of course, have evidentiary significance. It is often said that a reasonable person is unlikely to sleep on a well-founded claim. However, it has for long been clearly established that delay alone will not be fatal. A combination of delay and prejudice to the defendant is required to deprive the plaintiff of a specific remedy to which he or she is otherwise entitled. [3] In a decision of the Supreme Court of Canada, Duff J. described the principle as follows:

> The doctrine of laches, it has been frequently said, is not a technical doctrine, and in order to constitute a defence there must be such a change of position as would make it inequitable to require the defendant to carry out the contract or the delay must be of such a character as to justify the inference that the plaintiffs intended to abandon their rights under the contract or otherwise to make it unjust to grant specific performance. [4]

As Megarry V.C. explained in a case where there had been a lengthy delay but no apparent prejudice to the defendant on that account: “If specific performance was to be regarded as a prize, to be awarded by equity to the zealous and denied to the indolent, then the plaintiffs should fail. But whatever might have been the position over a century ago that was the wrong approach today.” [5] The test for equitable defences based upon delay was explained in the following terms by La Forest J. in *M. (K.) v. M. (H.)*: [6]

> A good discussion of the rule and of laches in general is found in Meagher, Gummow and Lehane, [*Equity Doctrines and Remedies* (1984)] at pp. 755-65, where the authors distil the doctrine in this manner, at p. 755:
>
>> “It is a defence which requires that a defendant can successfully resist an equitable (although not a legal) claim made against him if he can demonstrate that the plaintiff, by delaying the institution or prosecution of his case, has either (*a*) acquiesced in the defendant's conduct or (*b*) caused the defendant to alter his position in reasonable reliance on the plaintiff's acceptance of the status quo, or otherwise permitted a situation to arise which it would be unjust to disturb …”

> Thus there are two distinct branches to the laches doctrine, and either will suffice as a defence to a claim in equity. What is immediately obvious from all of the authorities is that mere delay is insufficient to trigger laches under either of its two branches. Rather, the doctrine considers whether the delay of the plaintiff constitutes acquiescence or results in circumstances that make the prosecution of the action unreasonable. Ultimately, laches must be resolved as a matter of justice as between the parties, as is the case with any equitable doctrine.

Prejudice of this nature on account of delay is peculiar to the context of specific relief and difficult to imagine in the case of monetary relief. The burden of specific relief on the defendant may increase because of changes induced by the plaintiff's conduct. Rarely will it be more onerous to pay damages later rather than sooner.[7]

In this area, terminology has not been used consistently. The words "laches", "acquiescence" and "waiver" are all used with varying meaning. Formerly, "laches" appears to have referred to simple delay unaccompanied by prejudice[8] whereas "acquiescence" was used to describe the situation of delay combined with a change of position making it inequitable to grant specific relief.[9] However, "acquiescence" is also sometimes used to describe the more complete defence equivalent to release or waiver barring the plaintiff from suing at all,[10] where the plaintiff stands by while his or her rights are infringed, "in such a manner as really to induce the person committing the act, and who might otherwise have abstained from it, to believe that he consents to its being committed".[11] Acquiescence, in this sense, is equivalent to waiver and affects the very existence of the substantive right, rather than just the availability of a specific remedy. The focus here will be on the effect of delay which has less drastic effect and which is relevant to the issue of remedial choice, that is, delay sufficient to deprive the plaintiff of specific relief but not to bar action altogether.[12]

Footnotes

1 Cudworth (Town) v. Central Plains District Health Board (1997), 157 Sask. R. 186 at p. 196 (Q.B.); Smith v. Dawgs Canada Distribution Ltd., [2008] 11 W.W.R. 342, 167 A.C.W.S. (3d) 899 (Sask. Q.B.); Van v. Qureshi (2013), 33 R.P.R. (5th) 265, 228 A.C.W.S. (3d) 1177 (Ont. S.C.J.), citing this passage with approval at para. 68, affd 41 R.P.R. (5th) 170, 238 A.C.W.S. (3d) 1041 (Ont. C.A.); Cardinal v. Cleveland Indians Baseball Co. Limited Partnership (2016), 134 O.R. (3d) 358 at para. 69, 134 O.R. (3d) 340 (Ont. S.C.J.).

2 McDonald Bankruptcy (Re) (2017), 284 A.C.W.S. (3d) 692, 2017 BCSC 1957 (B.C. S.C.), citing this passage with approval at para. 126. See also, § 10:14, discussing election of remedies in the context of specific performance.

3 McDonald Bankruptcy (Re) (2017), 284 A.C.W.S. (3d) 692, 2017 BCSC 1957 (B.C. S.C.), citing this passage with approval at para. 127; Lindsay Petroleum Co. v. Hurd (1874), L.R. 5 P.C. 221; Lamare v. Dixon (1873), L.R. 6 H.L. 414 at p. 421, *per* Lord Chelmsford: "quiescence is not acquiescence"; Archbold v. Scully (1861), 9 H.L.C. 360 at pp. 363 and 388, 11 E.R. 769; Erlanger v. New Sombrero Phosphate Co. (1878), 3 App. Cas. 1218 at p. 1279; Taylor v. Wallbridge (1879), 2 S.C.R. 616; Shorb v. Public Trustee (1954), 11 W.W.R. (N.S.) 132 (Alta. S.C. App. Div.); Blundon v. Storm, [1972] S.C.R. 135, 20 D.L.R. (3d) 413; Canada Trust Co. v. Lloyd, [1968] S.C.R. 300, 66 D.L.R. (2d) 722, motion to vary judgment refused [1968] S.C.R. vii; Gutheil v. Rural Municipality of Caledonia No. 99 (1964), 48 D.L.R. (2d) 628, 50 W.W.R. 278 (Sask. Q.B.); R. v. Landreville (No. 2), [1977] 2 F.C. 726, 75 D.L.R. (3d) 380 (T.D.); Ray Plastics Ltd. v. Dustbane Products Ltd. (1990), 75 O.R. (2d) 37, 33 C.P.R. (3d) 219, supplementary reasons 47 C.P.C. (2d) 280, C.P.R. *loc. cit.* p. 237 (H.C.J.); Mountain Ash Court Property Owners Assn. v. Dartmouth (City) (1994), 115 D.L.R. (4th) 361 at p. 367, 132 N.S.R. (2d) 74 (C.A.); LeMay v. Manitoba Metis Federation Inc. (1996), 110 Man. R. (2d) 226, 118 W.A.C. 226 (C.A.); Cadbury Schweppes Inc. v. FBI Foods Ltd., [1999] 1 S.C.R. 142, 167 D.L.R. (4th) 577 at p. 611, [1999] 5 W.W.R. 751; Boehringer Ingelheim (Canada) Ltd. v. Bristol-Myers Squibb Canada Inc. (1998), 78 C.P.R. (3d) 67 (Ont. Ct. (Gen. Div.)); Whitehorse Condominium Corp. No. 95 v. 37724 Yukon Inc., 2013 YKSC 4, 2013 CarswellYukon 2 (Y.T.S.C.), citing this passage with approval at para. 110.

4 Bark-Fong v. Cooper (1913), 49 S.C.R. 14 at p. 23, 16 D.L.R. 299. This paraphrases the often-cited statement of the principle of laches in Lindsay Petroleum Co. v. Hurd (1874), L.R. 5 P.C. 221, at pp. 239-40, *per* Sir Barnes Peacock:

> Now the doctrine of laches in Courts of Equity is not an arbitrary or a technical doctrine. Where it would be practically unjust to give a remedy, either because the party has, by his conduct, done that which might fairly be regarded as equivalent to a waiver of it, or where by his conduct and neglect he has, though perhaps not waiving that remedy, yet put the other party in a situation in which it would not be reasonable to place him if the remedy were afterwards to be asserted, in either of these cases, lapse of time and delay are most material…. Two circumstances, always important in such cases, are, the length of the delay and the nature of the acts done during the interval, which might affect either party and cause a balance of justice or injustice in taking the one course or the other, so far as relates to the remedy.

This passage is also quoted and applied in M. (K.) v. M. (H.), [1992] 3 S.C.R. 6 at p. 76, 96 D.L.R. (4th) 289 at p. 333, and in Cadbury Schweppes Inc. v. FBI Foods Ltd., [1994] 8 W.W.R. 727 at p. 751, 93 B.C.L.R. (2d) 318 (S.C.); Harris v. McNeely (2000), 47 O.R. (3d) 161, 130 O.A.C. 282 (C.A.); Pitblado & Hoskin v. Swerid (2003), 233 D.L.R. (4th) 290, [2004] 7 W.W.R. 80 (Man. C.A.).

5 Lazard Brothers & Co. Ltd. v. Fairfield Properties Co. (Mayfair) Ltd. (1978), 121 Sol. Jo. 793 (Ch.).

6 M. (K.) v. M. (H.), [1992] 3 S.C.R. 6 at p. 76, 96 D.L.R. (4th) 289, at pp. 77-8 (S.C.R.).

7 Compare the change of position defence in the law of restitution: Maddaugh and McCamus, The Law of Restitution, looseleaf ed. (Toronto: Thomson Reuters), at para. 10.500.10.

8 Milward v. Earl Thanet (1801), 5 Ves. Jun. 720*n*, 31 E.R. 824*n*, *per* Lord Alvanley M.R.: “A party cannot call upon a Court of Equity for a specific performance unless he has shewn himself ready, desirous, prompt, and eager.” See also Eads v. Williams (1854), 24 L.J. Ch. 531 at p. 535, *per* Lord Cranworth L.C.: “specific performance is relief which this Court will not give, unless in cases where the parties seeking it come as promptly as the nature of the case will permit”.

9 See also Meagher, Gummow and Lehane, Equity: Doctrines and Remedies, 5th ed. (Sydney, Butterworths, 2015), at Chapter 38, for discussion of the various meanings attributed to acquiescence.

10 See Brunyate, Limitation of Actions in Equity (London, Stevens & Sons Ltd., 1932), at p. 189: “Where lapse of time is an element in the more general defence that the plaintiff has released or waived his right or has elected not to assert them or is estopped from asserting them, then lapse of time is said to operate by way of acquiescence”; Willmott v. Barber (1880), 15 Ch. D. 96; Anderson v. Municipality of South Vancouver (1911), 45 S.C.R. 425, 1 W.W.R. 728. The view that there are different rules for legal and equitable rights was satisfactorily disposed of in Habib Bank Ltd. v. Habib Bank AG Zurich, [1981] 2 All E.R. 650 (C.A.), at p. 666, *per* Oliver L.J.: “such distinctions are both archaic and arcane and … in the year 1980 they have but little significance for anyone but a legal historian”.

11 De Bussche v. Alt (1878), 8 Ch. D. 286 (C.A.), at p. 314, *per* Thesiger L.J. See also Duke of Leeds v. Earl of Amherst (1846), 2 Ph. 117 at p. 123, 41 E.R. 886; Archbold v. Scully (1861), 9 H.L.C. 360 at p. 383, 11 E.R. 769, *per* Lord Wensleydale: “If a party, who could object, lies by and knowingly permits another to incur an expense in doing an act under the belief that it would not be objected to, and so a kind of permission may be said to be given to another to alter his condition, he may be said to acquiesce.” For the application of laches and acquiesence to municipalities with respect to the enforcement of bylaws, see Aubrey v. Prince (Township) (2001), 52 O.R. (3d) 274, 16 M.P.L.R. (3d) 127 (S.C.J.); Toronto (City) v. San Joaquin Investments Ltd. (1978), 83 D.L.R. (3d) 584 at p. 596, 18 O.R. (2d) 730 (H.C.J.), affd 106 D.L.R. (3d) 546, 26 O.R. (2d) 775, 11 M.P.L.R. 83 (C.A.), leave to appeal to S.C.C. refused 26 O.R. (2d) 775*n*, 11 M.P.L.R. 83*n* (S.C.C.):

> The doctrine of estoppel normally does not apply to a municipal corporation but where lands have been used and acknowledged as having been used over a period of almost 50 years and a municipality applies for an equitable remedy such as an injunction, consideration should be given to this usage and recognition.

See also Putt v. Kunetsky (2010), 92 R.P.R. (4th) 292, 187 A.C.W.S. (3d) 868 (B.C.S.C.) (private owner entitled to an injunction to restrain a substantial violation of a statutory building scheme despite acquiescence to minor infringements).

12 Cadbury Schweppes Inc. v. FBI Foods Ltd., [1994] 8 W.W.R. 727 at p. 751, 93 B.C.L.R. (2d) 318 (S.C.), at p. 612.

