ONTARIO ENERGY BOARD

EB-2022-0200

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 Enbridge Gas Inc. to change its natural gas rates and other charges beginning January 1, 2024

Environmental Defence Cross-Examination Compendium For Panel 10 – Customer Attachment Costs

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July 26, 2023

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E.B.O. 188

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c. O.13;

AND IN THE MATTER OF a hearing to inquire into, hear and determine certain matters relating to natural gas system expansion for The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc.

BEFORE: G.A. Dominy
Presiding Member

R.M.R. Higgin
Member

J.B. Simon
Member

FINAL REPORT OF THE BOARD

January 30, 1998

3. COMMON METHODS FOR FINANCIAL FEASIBILITY ANALYSIS

3.1 INTERIM REPORT CONCLUSIONS

3.1.1 *The Board believes that a further review of the methodology to be used by the utilities in assessing the project and portfolio financial feasibility is necessary. Among the factors to be considered are the period for new attachments and the time period over which the DCF analysis is calculated. The Board expects utilities to develop common methods for the Stage I Financial Feasibility test that will be used to show whether or not each utility's portfolio of distribution system expansion projects is profitable.*

3.2 POSITIONS OF THE PARTIES

3.2.1 The ADR Agreement set the following parameters for the DCF analysis:

(a) Customer Attachment Horizon

A maximum 10 year forecast horizon will be utilized. For customer attachment periods of greater than 10 years an explanation of the extension of the period will be provided to the Board.

(b) Customer Revenue Horizon

The maximum customer revenue horizon shall be 40 years from the in-service date of the initial mains, except for large volume customers where the maximum shall be 20 years from the customers' initial service.

(c) Discount Rate

The Utilities' incremental after-tax cost of capital will be used for the discount rate. This will be based on the prospective capital mix, debt and preference share costs, and the latest Board approved equity return levels.

(d) Discounting

Discounting will reflect the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted, as will revenue, gas related costs, and operating and maintenance expenditures.

(e) Operating and Maintenance Expenditures

The incremental costs directly associated with the attachment of new customers to the system will be included in the operating and maintenance expenditures.

(f) Gas Costs

In the near term, the weighted average cost of gas ("WACOG") will continue to be the proxy for gas costs (gas costs shall be WACOG less the commodity portion of the gas costs). This approach may not be appropriate in the case of projects for large customers, where a specific gas cost forecast may be required.

3.2.2 The parties to the Dissent Document submitted the ADR Agreement was deficient in that the utilities had not agreed on a common method for calculating their P.I.s; that a 40 year revenue horizon may result in existing customers paying undue rate increases; and that 40 years is inappropriate in the absence of shareholder responsibility for forecast variations.

3.2.3 The Dissent Document also stated that the utilities were understating the costs in the financial feasibility analysis, since they are not using incremental costs for gas storage and transportation services, but have proposed that gas costs be WACOG less the commodity portion of gas costs.

3.2.4 The Dissent Document proposed:

- a customer attachment horizon no longer than 5 years (unless there is a specific contract);
- a maximum time period for the DCF calculation of 20 years from the in-service date of the initial main for large volume customers and between 20 and 30 years for small volume customers;
- customer use volumes representing the best estimates of the gas consumption for new customers; and
- the inclusion of incremental costs associated with gas storage and TransCanada PipeLines Limited transmission.

3.3 BOARD'S COMMENTS AND FINDINGS

3.3.1 The Board notes that the utilities have undertaken to apply consistent business principles for the development of the elements of the financial feasibility test. These elements include: customer attachment horizon, customer revenue horizon, discount rate and timing, operating and maintenance expenditures, and weighted average gas costs.

3.3.2 The Board notes that the proposed customer attachment forecast horizon of 10 years is a maximum and adopts this as part of the Guidelines in Appendix B.

3.3.3 The Board is concerned that a customer revenue horizon of 40 years will encourage inclusion of projects with very long cash flow break-even periods and hence high levels of subsidy in the early years. The Board has addressed this issue as part of the design targets for the Investment Portfolio.

3.3.4 The Board concludes that, although theoretically correct, the inclusion of forecast incremental costs for the transportation and storage of gas will add unnecessary complexity to the DCF calculations for distribution system expansion projects.

3.3.5 The Board finds however that the methodology should include a standard test or measure to assess short term rate impacts at the Portfolio level. This would be similar to the Rate Impact Measure ("RIM") Test used to evaluate Demand Side Management ("DSM") programs, with the objective of allowing comparisons from year to year and, to a degree, among the separate portfolios of the utilities.

3.3.6 The Board accepts that the DCF calculation will be based on a set of common elements as proposed in the ADR Agreement. These common elements will be reflected in the DCF analysis for the Investment Portfolio and the Rolling Project Portfolio filed by each of the utilities in its rates cases, the details of which are set out in Appendix B.

Enbridge Gas – Panel 10 – Customer Attachment Policies
Examination in Chief – Table 1

Customer Connections Capital Expenditure Supported by Different Revenue Horizons

Revenue Horizon	2024	2025	2026	2027	2028	Total	Reduction vs. 40 Year Revenue Horizon	CIAC per Customer
(Years)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	
40	304	248	258	254	250	1,314		
30	238	235	247	249	262	1,231	83	428
25	214	211	223	225	235	1,108	206	1,067
15	146	144	153	154	159	757	557	2,890
10	89	88	93	95	96	460	853	4,428

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

Enbridge Gas - Panel 10
Customer Attachment Policies
Examination in Chief - Table 2

Impact on Customer Revenue Horizon based on
Equipment Replacement Assumptions

Customers Renewing at Equipment End of Life	Years of Revenue		Blended Revenue Horizon
	Yrs. 1-20	Yrs. 21-40	
100%	20	20	40
75%	20	15	35
50%	20	10	30
25%	20	5	25
10%	20	2	22
0%	20	-	20

Note - Assumes 20-year equipment life

Table 2: Capital Expenditures – 2023 to 2032 /u

Investment Sub-Category	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gas Infrastructure - Replacement - Reactive	51.2 M	60.7 M	40.6 M	44.1 M	56.6 M	72.4 M	58.3 M	61.4 M	76.7 M	58.9 M
Gas Infrastructure - Replacement - Proactive - Short Term (1y +)	353.9 M	147.5 M	283.7 M	126.1 M	153.5 M	60.6 M	60.9 M	63.0 M	66.6 M	62.5 M
Gas Infrastructure - Replacement - Proactive - Long Term (20y +)	1.9 M	1.4 M	0.9 M	11.8 M	18.5 M	94.0 M	146.6 M	208.7 M	270.7 M	320.5 M
Gas Infrastructure - Replacement - Proactive - Long Term Cost Effectiveness*	34.0 M	39.7 M	113.5 M	75.4 M	64.6 M	75.3 M	74.1 M	64.0 M	69.5 M	124.5 M
Gas Infrastructure - Sustainment	391.8 M	472.7 M	406.6 M	439.0 M	378.6 M	367.7 M	345.8 M	359.1 M	361.9 M	357.3 M
Gas Infrastructure - Growth - Customer Connection	325.0 M	333.6 M	285.9 M	296.7 M	294.8 M	269.6 M	261.3 M	261.6 M	254.5 M	243.0 M
Gas Infrastructure - Growth - System Reinforcemer	112.8 M	277.4 M	268.9 M	176.9 M	262.8 M	140.9 M	220.8 M	51.8 M	27.3 M	103.0 M
Business Sustainment	119.9 M	195.8 M	171.6 M	204.1 M	122.9 M	163.2 M	121.6 M	139.5 M	139.3 M	125.1 M
Emission Reductions	0.8 M	1.8 M	4.1 M	1.2 M	11.9 M	0.0 M	0.0 M	0.0 M	0.0 M	0.0 M
Energy Transition	38.4 M	134.1 M	55.0 M	31.5 M	28.0 M	35.7 M	25.0 M	25.0 M	25.0 M	25.0 M
Grand Total	**1429.9 M**	**1665.2 M**	**1630.5 M**	**1406.7 M**	**1392.3 M**	**1279.5 M**	**1314.5 M**	**1234.1 M**	**1291.5 M**	**1419.7 M**

4. Summary

28. Enbridge Gas has prioritized its capital expenditures over the 2013 to 2024 period in order to ensure the safety and reliability of the natural gas distribution system while supporting system growth. Enbridge Gas continues to follow established budget processes to prioritize capital expenditures and accommodate the majority of capital projects within approved base rates. Enbridge Gas provided a Capital Update provided at Exhibit 2, Tab 5, Schedule 4, on June 16, 2023, to address emerging cost pressures and evolving business requirements for 2023 and 2024 and has reprioritized projects accordingly to remain within the proposed constraints for capital expenditures. The evidence provided at Exhibit 2, Tab 5, Schedule 2 further describes the prioritized spend for the 2024 Test Year. The evidence provided at Exhibit 2, Tab 5, Schedule 3 summarizes the historical capital expenditures for EGD and Union under their individual IR terms and details the year-over-year capital expenditure variances for Enbridge Gas during the deferred rebasing term. /u

annual capital expenditures by Asset Class, as shown in the Capital Update provided at Exhibit 2, Tab 5, Schedule 4. Categories of spend not included in the Asset Management Plan (AMP) include Community Expansion and Other which includes Renewable Natural Gas (RNG) and Compressed Natural Gas (CNG). /u

Table 1
Utility Capital Expenditures by Asset Class

Line No.	Particulars ($ millions)	Category	2024 Test Year (a)	2025 Forecast (b)	2026 Forecast (c)	2027 Forecast (d)	2028 Forecast (e)	
1	Compression Stations	Storage	46.3	64.3	50.3	127.6	19.2	/u
2	Customer Connections	Growth	304.1	248.1	256.9	254.0	250.1	/u
3	Distribution Pipe	Dist Ops	357.1	414.4	282.7	250.2	316.4	/u
4	Distribution Stations	Dist Ops	83.5	113.1	105.5	79.0	116.3	/u
5	Fleet & Equipment	General	31.5	35.4	40.1	45.7	52.3	/u
6	Growth - Distribution System Reinforcement	Growth	85.2	200.0	43.4	46.0	10.3	/u
7	Real Estate & Workplace Services	General	63.0	61.3	92.0	32.0	56.4	/u
8	Technology Information Services	General	102.4	78.0	71.0	44.9	54.1	/u
9	Transmission Pipe and Underground Storage	Storage	69.2	144.8	201.5	268.4	169.9	/u
10	Utilization	Dist Ops	152.3	160.1	172.6	152.0	168.4	/u
11	EA Fixed Overhead	Other	39.8	40.8	41.9	43.0	23.2	/u
12	Community Expansion	Growth	11.2	19.6	20.5	21.5	7.3	/u
13	Other	Other	124.6	43.9	28.3	28.0	35.7	/u
14	Total		1,470.3	1,623.8	1,406.7	1,392.3	1,279.5	/u

Notes:
(1) Expenditures are shown by Asset Class inclusive of IDC and Overheads and net of contributions
(2) Expenditures are shown on an annual basis
(3) Panhandle Regional Expansion Project capex reductions of $194.9M in 2024 and $6.7M in 2025

Year. Through consultation with internal stakeholders and in consideration of the asset class strategies, management of risk, ability to complete mandatory work, Customer Engagement Survey results and total in-service capital spend, a constraint of $1.2 billion with a 2% escalation factor was recommended. Enbridge Gas is not able to complete mandatory work or support the demand for growth at a constraint below $1.2 billion. The constraint of $1.2 billion is required to safely operate and maintain the natural gas system, respond to demand growth, invest in low-carbon solutions and ensure on-going reliability and service to customers.

3. Capital Expenditure Forecasts – 2023 to 2032 /u

22. Figure 2 provides a different view of Enbridge Gas's capital expenditures[6] from 2023 to 2032, with expenditures re-classified into three main categories: Sustainment, Replacement and Growth. This presentation reflects investment requirements to maintain the current gas transmission, distribution and storage systems (Sustainment and Replacement) and the investment requirements for Growth of those same systems. Also included are other smaller categories related to Energy Transition, Emission Reductions and Business Sustainment.

23. The main categories and sub-categories set out in Figure 2 are as follows: /u

Table 1: Investment Categories /u

General Investment Category	Investment Sub-Category
Replacement	**Gas Infrastructure – Replacement – Reactive**: This investment category is comprised of emergency

[6] The capital expenditures in Figure 1 are lower than those in Section 2 and Figure 2. The difference is due to Enbridge Gas's proposal of a levelized approach to cost recovery for PREP. Figure 1 has excluded capital expenditures related to PREP of $22.7M in 2023 and $194.9M in 2024 as part of the Capital Update.

	life or maintain the current function of existing assets. Also included in this category are investments necessary to maintain compliance or address known safety/reliability risks that cannot otherwise be mitigated. Examples include integrity programs; compliance programs; relocation programs; component replacements and overhauls for stations, LNG, compressor and storage assets (required based on performance degradation, failures, risk, condition or obsolescence); pipeline replacements to address inoperable valves, and small distribution station replacements to address risks that cannot be addressed through component replacements.
Growth	**Gas Infrastructure – Growth – Customer Connections**: This investment category includes all costs associated with connecting new customers to Enbridge Gas's distribution, transmission and storage system, including costs for meters associated with new customer attachments. Community Expansion is included in this investment category.
	Gas Infrastructure – Growth – System Reinforcement: This investment category is required to maintain minimum system pressures so that demand for gas can be met during design day conditions.
Business Sustainment	**Business Sustainment**: This investment category is comprised of TIS, REWS and fleet investments including CNG station replacements/builds for Enbridge Gas's fleet.
Emission Reductions	**Emission Reductions**: This investment category relates to expenditures to reduce emissions, other than those emission reductions required for compliance reasons.
Energy Transition	**Energy Transition**: This investment category relates to increasing the use of hydrogen and RNG/CNG.

Customer Additions (Actual and Forecast)

Line No.	Sector	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Residential												
1	New Construction	36,895	36,629	36,572	39,637	44,042	40,853	35,027	35,409	35,021	34,963	34,513	33,609
2	Replacement	14,111	15,128	11,403	8,369	7,465	6,831	6,103	5,537	5,038	5,066	4,878	5,639
3	Total	51,006	51,757	47,975	48,006	51,507	47,684	41,130	40,946	40,059	40,029	39,391	39,248
	Commercial												
4	New Construction	3,318	3,123	2,893	2,648	2,706	2,555	2,553	1,976	1,889	2,082	1,975	1,879
5	Replacement	508	730	725	525	740	582	470	427	476	496	477	489
6	Total	3,826	3,853	3,618	3,173	3,446	3,137	3,023	2,403	2,365	2,578	2,452	2,368
	Industrial												
7	New Construction	68	56	61	42	47	38	40	19	49	35	33	31
8	Replacement	3	2	3	3	1	0	1	1	9	0	3	1
9	Total	71	58	64	45	48	38	41	20	58	35	36	32
10	Total Customer Additions	54,903	55,668	51,657	51,224	55,001	50,859	44,194	43,369	42,482	42,642	41,879	41,648

Table 4
Customer Attachments by Type Before Energy Transition Impact

	Community Expansion (CE)	Fuel Switching Other than CE	Homes in residential developments (subdivisions)	Single family dwellings (Apartment Ensuite)	Other
2020	564	5,535	30,106	5,305	2,423
2021	428	4,953	33,268	1,741	2,420
2022	314	4,834	30,641	4,279	2,574
2023	579	4,548	30,233	4,282	2,456
2024	1,257	4,640	29,508	4,222	2,342
2025	2,019	4,505	28,841	4,168	2,230
2026	1,802	4,371	28,211	4,119	2,120
2027	1,388	4,229	27,256	4,023	2,015
2028	1,053	4,102	26,057	3,892	1,910
2029	714	3,783	25,301	3,820	1,808
2030	630	3,673	24,567	3,749	1,709
2031	380	3,569	23,854	3,681	1,612
2032	363	3,474	23,166	3,613	1,517

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

In the table at Exhibit 2, Tab 5, Schedule 2, does community expansion (line 12) include the individual connections in community expansion areas, or are those included in line 2 (customer connections)? If the latter, please provide a breakout of the customer connections costs in line 2 between subcategories (community expansion, etc.).

Response:

Customer additions related to Community Expansion projects are included in line 12 (Community Expansion) of Table 1 in Exhibit 2, Tab 5, Schedule 2.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

For infill connections, how much connection capital (e.g. for the service line and meter) could be supported based on forecast revenue for a single residential customer (on an NPV basis – i.e. meeting a PI of 1) over (a) 10 years and (b) 15 years?

Response:

The capital amount that can be supported by the distribution revenue of a residential customer is as follows.

a) Based on a 10-year revenue horizon - $2,713
b) Based on a 15-year revenue horizon - $3,658

customers, should they request this service. The proposed charge is greater than the current charges in the EGD and Union rate zones for meter dispute test services for residential customers because the previous charges have not been updated in over 10 years and no longer reflect the cost to provide the service. The proposed charge may be lower than the current custom charge for some non-residential customers depending on specific customer circumstances.

1.7. ELC[4]

37. Enbridge Gas uses the extra length rule to assess feasibility of residential infill[5] customers. Currently, the rule assumes standard residential services are economically feasible to a threshold length of 20 metres for the EGD rate zone and 30 metres for the Union rate zones. Customers pay an ELC when the service length exceeds these thresholds. The current approved ELC is $32 per additional metre for the EGD rate zone and $45 per additional metre for the Union rate zones. Despite increases in construction costs, these ELC rates have remained constant for many years and require updating to reflect the latest marginal cost per metre. The ELC collected is accounted for as a reduction to capital investment or a credit to assets.

38. Enbridge Gas is proposing a harmonized service length threshold of 20 metres and an updated ELC of $122 per additional metre that will apply consistently across all franchise areas. Service length threshold and ELC have been determined in consideration of various factors including results from the customer engagement and internal data analysis as described below. The customer engagement showed that customers had varying preferences when considering the options presented (of

[4] Charge was previously called street service alteration on Rider G.
[5] Residential infills are existing homes which are converting from other fuel types to natural gas to meet their energy needs.

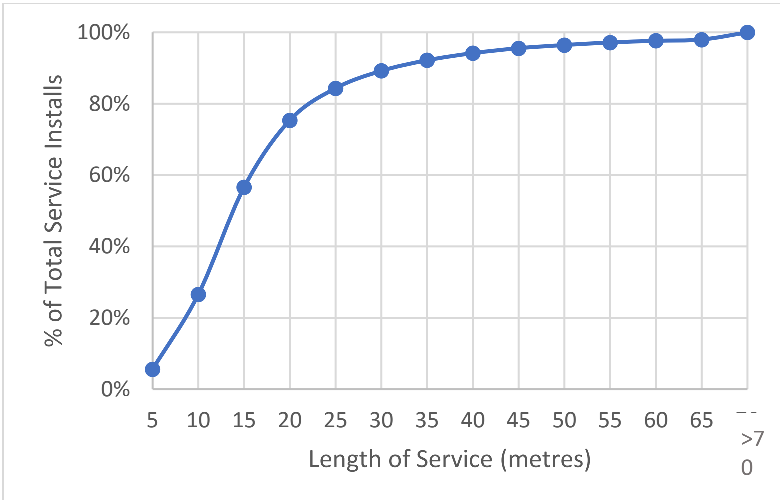
a shorter or longer length for the service length threshold and associated ELC), with no strong preference for one option. Approximately one third of customers (32%) indicated a preference of 15 metres with a lower ELC, a combined 35% indicated a preference of 20 metres (22%) or 25 metres (13%) with a higher ELC, and the remaining 32% had no preference or indicated don't know. Further details can be found in the customer engagement report provided at Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 279-280.

Proposed Service Length Threshold

39. Enbridge Gas is proposing that residential infill customers be provided with the first 20 metres of service at no cost. The length of the service will be measured from the customer's property line to the location where the gas meter is installed. Service lengths beyond the threshold length of 20 metres will be subject to the ELC.

40. The proposed service length threshold is based on data from residential infill services installed between 2018 to 2020. Based on this data, it was determined that the distribution revenue from a typical residential customer can support the average cost of services below 20 metres. As shown in Figure 1, approximately 75% of residential services are less than or equal to 20 metres. As such, the proposed service length threshold will result in the Company attaching most infill services with no accompanying ELC. This anticipated outcome will support continued efficiencies in the infill service attachment process while also ensuring no undue cross-subsidization.

Figure 1: Residential Service Length by % of Total Service Installs, 2018 to 2020

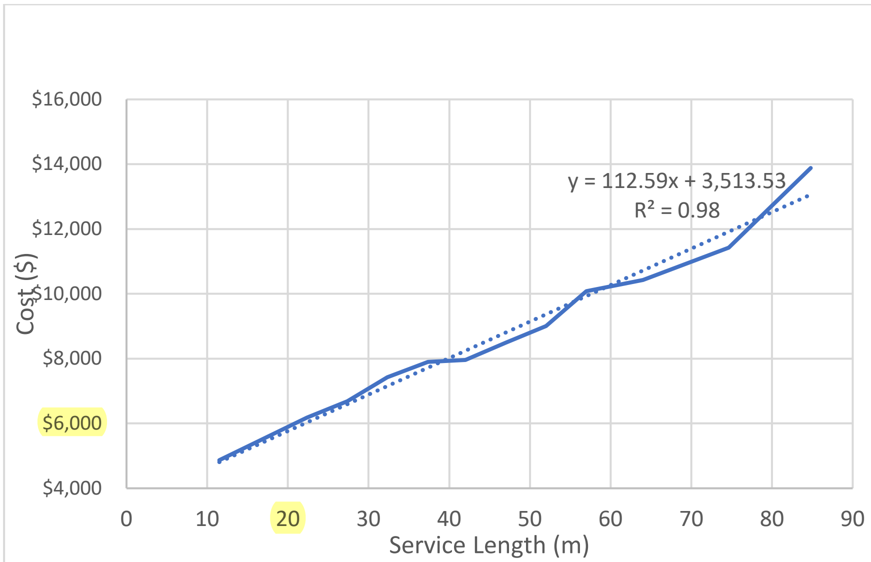


Proposed ELC

41. Enbridge Gas is proposing an ELC of $122 per metre in excess of the 20-metre service length threshold. The ELC of $122 per metre in 2024 has been calculated based on the actual cost of $113 per metre established for 2020, as described in this section of evidence, escalated for annual inflation of 2%.

42. The ELC of $113 per metre (for 2020 prior to inflation), represents the marginal cost per metre and was determined through a linear regression of historical service costs vs. service length, as shown in Figure 2. The regression analysis was conducted using actual service lengths and costs over the 3-year period from 2018 to 2020, across all rate zones. The equation of the regression trend line (y=113x + 3514) in Figure 2 indicates two cost components; 1) the slope of the line that is $113 represents the marginal (or variable) cost per metre and 2) fixed cost is $3,514. The regression results indicate a strong correlation between cost and length, as evident from a high R-squared (0.98) value.

Figure 2: Average Service Cost, 2018 to 2020



43. The proposed cost per metre for ELC is higher compared to the current EGD and Union ELC because the charges have not been updated in over 10 years. Since then, construction costs have increased due to various factors including inflation, enhancement in safety standards, extensive use of trenchless technology, sewer safety and cross bore mitigation requirements, and additional costs related to municipal permit fee and restoration requirements.

1.8. Locate Delivery Service Charge

44. Enbridge Gas currently provides locate delivery services upon request from customers[6], third-party contractors and other utilities at no extra charge.

45. Bill 93, the Getting Ontario Connected Act, 2022[7], was recently passed into law on April 14, 2022. Bill 93 imposes significant changes to how locates are delivered in

[6] Occupants of residential and/or private property.
[7] Bill 93, Getting Ontario Connected Act, 2022, April 14, 2022. https://www.ola.org/sites/default/files/node-files/bill/document/pdf/2022/2022-04/b093ra_e.pdf

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 67

To advise how much it costs to connect a home to the gas grid, on average, focusing only on those costs paid for via rates, and also how long it would take for the rates from that single home to pay off those connection costs for an average home, without TCS or SES. On average how much are the connection costs and on average how long would it take with rates to pay off those connection costs. Not including the SES or TCS costs.

Response:

The average cost to connect a home[1] to the gas system in the EGD rate zone is $4,238 which would take approximately 29 years to recover through distribution rates. The data to determine the cost to connect a home to the gas system in the UG rate zones is not available, however the average cost to connect a customer for the UG rate zones is $4,791 which would take approximately 30 years to recover through distribution rates.[2]

[1] The average cost to connect a home in the EGD rate zone includes the weighted average cost of both new construction and existing homes.
[2] The average cost to connect a customer in the Union rate zones, is the weighted average cost of all types of customers including residential, commercial, apartments and industrial.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 67

To advise how much it costs to connect a home to the gas grid, on average, focusing only on those costs paid for via rates, and also how long it would take for the rates from that single home to pay off those connection costs for an average home, without TCS or SES. On average how much are the connection costs and on average how long would it take with rates to pay off those connection costs. Not including the SES or TCS costs.

Response:

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023. /u

The average cost to connect a home[1] to the gas system in the EGD rate zone is $4,412 which would take approximately 31 years to recover through distribution rates. The data to determine the cost to connect a home to the gas system in the Union rate zones is not available, however the average cost to connect a customer for the Union rate zones is $6,261 which would take approximately 23 years to recover through distribution rates.[2] /u /u /u

Inadvertently, the revenue from the large volume customers was not included in calculating the recovery period for the Union rate zones in the original response. The correct recovery period corresponding to an average connection cost of $4,791 would have been 14 years instead of 30 years as provided in the original response. /u

[1] The average cost to connect a home in the EGD rate zone includes the weighted average cost of both new construction and existing homes.
[2] The average cost to connect a customer in the Union rate zones, is the weighted average cost of all types of customers including residential, commercial, apartments and industrial.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 67

To advise how much it costs to connect a home to the gas grid, on average, focusing only on those costs paid for via rates, and also how long it would take for the rates from that single home to pay off those connection costs for an average home, without TCS or SES. On average how much are the connection costs and on average how long would it take with rates to pay off those connection costs. Not including the SES or TCS costs.

Response:

The average cost to connect a home[1] to the gas system in the EGD rate zone is $5,673 /u
which would take approximately 31 years to recover through distribution rates. The data to determine the cost to connect a home to the gas system in the Union rate zones is not available, however the average cost to connect a customer for the Union rate zones is $8,097 which would take approximately 23 years to recover through distribution /u
rates.[2]

Inadvertently, the revenue from the large volume customers was not included in calculating the recovery period for the Union rate zones in the original response. The correct recovery period corresponding to an average connection cost of $4,791 would have been 14 years instead of 30 years as provided in the original response.

The average costs provided in the original response represented only the direct capital /u
cost and excluded the incremental overheads e.g. normalized system reinforcement, /u
which were already included in calculations of the recovery period. The updated response /u
represents the fully burdened costs of connecting a customer which are required for /u
testing feasibility as per OEB guidelines in E.B.O. 188, Appendix B, section 2.1. The /u
updated cost fully reflects the capital cost which is paid via rates – this will have no impact /u
on the referenced recovery period. /u

[1] The average cost to connect a home in the EGD rate zone includes the weighted average cost of both new construction and existing homes and is based on the 2024 forecast revenues and costs.
[2] The average cost to connect a customer in the Union rate zones, is the average cost of all types of customers including residential, commercial, apartments and industrial and is based on the 2024 forecast revenues and costs.

ENBRIDGE GAS INC.

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

Undertaking

Tr: 90

To provide what amount of capital does the margin that you get from one residential customer support to achieve a PI of 1. Also to do it for .7, so the same process, but establishing the PI level as .7, opposed to 1, just so we get some sensitivity on that.

Response:

The table below provides the capital amount that the margin from a residential customer can support to achieve different levels of Profitability Index.

	Profitability Index = 1.0	Profitability Index = 0.7
Capital Investment	$5,952	$8,884

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 209

To take under advisement as when by additional years.

Response:

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023. /u

The impacts presented below do not include 2024 PREP forecast in-service additions, consistent with the Capital Update, and related rate base impacts in future years. /u

This request asked Enbridge Gas to expand the response provided at Exhibit I.1.2-SEC-6 to provide an estimate of Enbridge Gas's total rate base each year until 2033.

Total rate base forecast for years 2024 to 2028 is provided in Table 1.

Table 1
2024 to 2028 Rate Base

($ millions)	2024	2025	2026	2027	2028	
Rate base	16,212.3	16,275.4	17,366.8	17,820.6	18,136.5	/u

Enbridge Gas is not providing a rate base forecast for the 2029 to 2032 period. This information does not relate to the relief requested in this Application. Any rate base amounts post 2028 would be subject to the rate setting mechanism(s) in place at that time, not yet proposed or known by the Company. Directionally, and based on the information and requests contained in the immediate Application, Enbridge Gas would expect rate base to increase from 2029 to 2032, however the average annual growth rate in rate base over that period would be less than the average annual growth rate from 2024 to 2028.

ONTARIO ENERGY BOARD

Distribution System Code

Last revised on July 1, 2022

(Originally Issued on July 14, 2000)

3.1.10 Where a customer requests the relocation of a distributor-owned asset, the distributor shall recover from that customer the cost of relocating that asset, except to the extent recovery is limited under law.

3.1.11 Where a distributor-owned asset is relocated in the absence of a customer request, the distributor shall bear the cost of relocating that asset.

3.2 Expansions

3.2.1 If a distributor must construct new facilities to its main distribution system or increase the capacity of existing distribution system facilities in order to be able to connect a specific customer or group of customers, the distributor shall perform an initial economic evaluation based on estimated costs and forecasted revenues, as described in Appendix B, of the expansion project to determine if the future revenue from the customer(s) will pay for the capital cost and on-going maintenance costs of the expansion project.

3.2.2 If the distributor's offer was an estimate, the distributor shall carry out a final economic evaluation once the facilities are energized. The final economic evaluation shall be based on forecasted revenues, actual costs incurred (including, but not limited to, the costs for the work that was not eligible for alternative bid, and any transfer price paid by the distributor to the customer) and the methodology described in Appendix B.

3.2.3 If the distributor's offer was a firm offer, and if the alternative bid option was chosen and the facilities are transferred to the distributor, the distributor shall carry out a final economic evaluation once the facilities are energized. The final economic evaluation shall be based on the amounts used in the firm offer for costs and forecasted revenues, any transfer price paid by the distributor to the customer, and the methodology described in Appendix B.

3.2.4 The capital contribution that a distributor shall charge an embedded distributor or a customer other than a generator to construct an expansion shall be equal to that customer’s share of the difference between the present value of the projected capital costs and on-going maintenance costs for the facilities and the present value of the projected revenue for distribution services provided by those facilities. The methodology and inputs that a distributor shall use to calculate this amount are described in Appendix B.

3.2.4A Where an expansion involves an upstream transmission asset that has been deemed by the Board to be a distribution asset pursuant to section 84 of the Act, a distributor shall not require a capital contribution under section 3.2.4 or section 3.2.27 from a load customer with a non-coincident peak demand of less than 5 MW.

3.2.5 The capital contribution that a distributor shall charge a generator to construct an expansion to connect a generation facility to the distributor's distribution system shall be equal to the generator's share of the present value of the projected capital costs and on-going maintenance costs for the facilities. Projected revenue and avoided costs from the generation facility shall be assumed to be zero, unless otherwise determined by rates approved by the Board. The methodology and inputs that a distributor shall use to calculate this amount are described in Appendix B.

3.2.5A Notwithstanding section 3.2.5 but subject to section 3.2.5B, a distributor shall not charge a generator to construct an expansion to connect a renewable energy generation facility:

(a) if the expansion is in a Board-approved plan filed with the Board by the distributor pursuant to the deemed condition of the distributor's licence referred to in paragraph 2 of subsection 70(2.1) of the Act, or is otherwise approved or mandated by the Board; or

(b) in any other case, for any costs of the expansion that are at or below the renewable energy generation facility's renewable energy expansion cost cap.

For greater clarity, the distributor shall bear all costs of constructing an expansion referred to in (a) and, in the case of (b), shall bear all costs of constructing the expansion that are at or below the renewable energy generation facility's renewable energy expansion cost cap.

3.2.5B Where an expansion is undertaken in response to a request for the connection of more than one renewable energy generation facility, a distributor shall not charge any of the requesting generators to construct the expansion:

(a) if the expansion is in a Board-approved plan filed with the Board by the distributor pursuant to the deemed condition of the distributor's licence referred to in paragraph 2 of subsection 70(2.1) of the Act, or is otherwise approved or mandated by the Board; or

(b) in any other case, for any costs of the expansion that are at or below the amount that results from adding the total name-plate rated capacity of each renewable energy generation facility referred to in section 6.2.9(a) (in MW) and then multiplying that number by $90,000.

For greater clarity, the distributor shall bear all costs of constructing an expansion referred to in (a) and, in the case of (b), shall bear all costs of constructing the expansion that are at or below the number that results from the calculation referred to in (b).

3.2.5C Where, in accordance with the calculation referred to in section 3.2.5B(b), a capital contribution is payable by the requesting generators, the distributor shall apportion the amount of the capital contribution among the requesting generators on a pro-rata basis based on the total name-plate rated capacity of the renewable energy generation facility referred to in section 6.2.9(a) (in MW).

3.2.6 If a shortfall between the present value of the projected costs and revenues is calculated under section 3.2.1, the distributor may propose to collect all or a portion of that amount from the customer in the form of a capital contribution, in accordance with the distributor's documented policy on capital contributions by customer class.

3.2.7 If the capital contribution amount resulting from the final economic evaluation provided for in section 3.2.2 or 3.2.3 differs from the capital contribution amount resulting from the initial economic evaluation calculation, the distributor shall obtain from the customer, or credit the customer for, any difference between the two calculations.

3.2.8 If an expansion is needed in order for a distributor to connect a customer, the distributor shall make an initial offer to connect the customer and build the expansion. A distributor's initial offer shall include, at no cost to the customer:

(a) a statement as to whether the offer is a firm offer or is an estimate of the costs that would be revised in the future to reflect actual costs incurred;

(b) a reference to the distributor's Conditions of Service and information on how the customer requesting the connection may obtain a copy of them;

(c) a statement as to whether a capital contribution will be required from the customer;

(d) a statement as to whether an expansion deposit will be required from the customer and if the distributor will require an expansion deposit from the customer, the amount of the expansion deposit that the customer will have to provide; and

(e) a statement as to whether the connection charges referred to in sections 3.1.5 and 3.1.6 will be charged separately from the capital contribution referred to in section 3.2.8(c), and a description of, and if known, the amount for, those connection charges.

3.2.9 If the distributor will require a customer to pay a capital contribution, the distributor must, in addition to complying with section 3.2.8, also include in its initial offer, at no cost to the customer:

(a) the amount of the capital contribution that the customer will have to pay for the expansion;

(b) the calculation used to determine the amount of the capital contribution to be paid by the customer including all of the assumptions and inputs used to produce the economic evaluation as described in Appendix B;

(c) a statement as to whether the offer includes work for which the customer may obtain an alternative bid and, if so, the process by which the customer may obtain the alternative bid;

(d) a description of, and costs for, the work that is eligible for alternative bid and the work that is not eligible for alternative bid associated with the expansion broken down into the following categories:

i) labour (including design, engineering and construction);

ii) materials;

iii) equipment; and

iv) overhead (including administration);

(e) an amount for any additional costs that will occur as a result of the alternative bid option being chosen (including, but not limited to, inspection costs);

(f) if the offer is for a residential customer, a description of, and the amount for, the cost of the basic connection referred to in section 3.1.4 that has been factored into the economic evaluation; and

(g) if the offer is for a non-residential customer and if the distributor has chosen to recover the non-residential basic connection charge as part of its revenue requirement, a description of, and the amount for, the connection charges referred to in section 3.1.5 that have been factored into the economic evaluation.

3.2.10 Once the customer has accepted the distributor's offer, and if the customer requests it, the distributor shall provide to the customer, at cost, an itemized list of the costs for the major items in each of the categories listed in section 3.2.9(d) and shall be done in the following manner:

(a) if the customer has not chosen to pursue an alternative bid, the distributor hall provide the itemized list for all of the work; or

(b) if the customer has chosen to pursue the alternative bid option, the distributor shall only be required to provide the itemized list for the work that is not eligible for alternative bid.

3.2.11 If the customer submits revised plans or requires additional design work, the distributor may provide, at cost, a new offer based on the revised plans or the additional design work.

3.2.12 The distributor shall provide the customer with the calculation used to determine the final capital contribution amount including all of the assumptions and inputs used to produce the final economic evaluation as provided for in sections 3.2.2 and 3.2.3. The distributor shall provide the final economic evaluation and final capital contribution amount to the customer at no cost to the customer.

3.2.13 The last sentence of section 3.2.12 does not apply to a customer who is a generator or is proposing to become a generator unless the customer's proposed or existing generation facility is an emergency backup generation facility.

3.2.14 Where the distributor requires a capital contribution from the customer, the distributor shall allow the customer to obtain and use alternative bids for the work that is eligible for alternative bid. The distributor shall require the customer to use a qualified contractor for the work that is eligible for alternative bid provided that the customer agrees to transfer the expansion facilities that are constructed under the alternative bid option to the distributor upon completion.

3.2.15 The following activities are not eligible for alternative bid:

(a) distribution system planning; and

(b) the development of specifications for any of the following:

i) the design of an expansion;

ii) the engineering of an expansion; and

iii) the layout of an expansion.

3.2.15A Work that requires physical contact with the distributor's existing distribution system is not eligible for alternative bid unless the distributor decides in any given case to allow such work to be eligible for alternative bid.

3.2.15B Despite any other provision of this Code, decisions related to the temporary de-energization of any portion of the distributor’s existing distribution system are the sole responsibility of the distributor. Where the temporary de-energization is required in relation to work that is being done under alternative bid, the distributor shall apply the same protocols and procedures to the de-energization as it would if the customer had not selected the alternative bid option.

3.2.16 If a customer chooses to pursue an alternative bid and uses the services of a qualified contractor for the work that is eligible for alternative bid, the distributor shall:

(a) require the customer to complete all of the work that is eligible for alternative bid;

(b) require the customer to:

i) select and hire the contractor;

ii) pay the contractor’s costs for the work that is eligible for alternative bid; and

iii) assume full responsibility for the construction of that aspect of the expansion;

(c) require the customer to be responsible for administering the contract (including the acquisition of all required permissions, permits and easements) or have the customer pay the distributor to do this activity;

(d) require the customer to ensure that the work that is eligible for alternative bid is done in accordance with the distributor's distribution system planning and the distributor’s specifications for any of the following:

i) the design of the expansion;

ii) the engineering of the expansion; and

iii) the layout of the expansion

(d.1) require the customer to obtain the distributor's review and approval of plans for the design, engineering, layout, and work execution for the work that is eligible for alternative bid to ensure conformance with the distribution system planning and specifications referred to in paragraph (d) prior to commencing that work; and

(e) inspect and approve, at cost, all aspects of the constructed facilities as part of a system commissioning activity, prior to connecting the constructed facilities to the existing distribution system.

3.2.17 In addition to the capital contribution amounts in sections 3.2.4 and 3.2.5, the distributor may also charge a customer that chooses to pursue an alternative bid any costs incurred by the distributor associated with the expansion including, but not limited to, the following:

(a) costs for additional design, engineering, or installation of facilities required to complete the project;

(a.1) costs associated with any temporary de-energization of any portion of the existing distribution system that is required in relation to an expansion that is constructed under the alternative bid option;

(a.2) costs associated with the review and approval referred to in section 3.2.16(d.1);

(b) costs for administering the contract between the customer and the contractor hired by the customer if the distributor is asked to do so by the customer and the distributor agrees to do it; and

(c) costs for inspection or approval of the work performed by the contractor hired by the customer.

When the customer transfers the expansion facilities to the distributor in accordance with section 3.2.18 and 3.2.19, the charges referred to above shall be included as part of the customer's costs for the purposes of determining the transfer price.

3.2.18 When the customer transfers the expansion facilities that were constructed under the alternative bid option to the distributor, and provided that the distributor has inspected and approved the constructed facilities, the distributor shall pay the customer a transfer price. The transfer price shall be the lower of the cost to the customer to construct the expansion facilities or the amount set out in the distributor's initial offer to do the work that is eligible for alternative bid. If the customer does not provide the distributor with the customer's cost information in a timely manner, then the distributor may use the amount for the work that is eligible for alternative bid as set out in its initial offer for the transfer price instead of the customer’s cost.

3.2.19 Where a distributor is required to pay a transfer price under section 3.2.18, the transfer price shall be considered a cost to the distributor for the purposes of completing the final economic evaluation.

3.2.20 For expansions that require a capital contribution, a distributor shall require the customer to provide an expansion deposit for up to 100% of the present value of the forecasted revenues as described in Appendix B. For expansions that do not require a capital contribution, a distributor may require the customer to provide an expansion deposit for up to 100% of the present value of the projected capital costs and on-going maintenance costs of the expansion project.

3.2.21 The expansion deposit collected under section 3.2.20 shall cover both the forecast risk (the risk associated with whether the projected revenue for the expansion will materialize as forecasted) and the asset risk (the risk associated with ensuring that the expansion is constructed, that it is completed to the proper design and technical standards and specifications, and that the facilities operate properly when energized) related to the expansion.

3.2.22 If the alternative bid option was chosen, a distributor shall be allowed to retain and use the expansion deposit to cover the distributor's costs if the distributor must complete, repair, or bring up to standard the facilities. Complete, repair, or bring up to standard includes costs the distributor incurs to ensure that the expansion is completed to the proper design and technical standards and specifications, and that the facilities operate properly when energized.

3.2.23 Once the facilities are energized and subject to sections 3.2.22 and 3.2.24, the distributor shall annually return the percentage of the expansion deposit in proportion to the actual connections (for residential developments) or actual demand (for commercial and industrial developments) that materialized in that year (i.e., if twenty percent of the forecasted connections or demand materialized in that year, then the distributor shall return to the customer twenty percent of the expansion deposit). This annual calculation shall only be done for the duration of the five-year customer connection horizon. If at the end of the customer connection horizon the forecasted connections (for residential developments) or forecasted demand (for commercial and industrial developments) have not materialized, the distributor shall be allowed to retain the remaining portion of the expansion deposit.

3.2.24 If the alternative bid option was chosen, the distributor shall retain at least ten percent of the expansion deposit for a warranty period for at least two years. This portion of the expansion deposit can be applied to any work required to repair the expansion facilities within the two year warranty period. The two year warranty period begins:

(a) when the last forecasted connection in the expansion project materializes (for residential developments) or the last forecasted demand materializes (for commercial and industrial developments); or

(b) at the end of the five-year customer connection horizon,

whichever is first. The distributor shall return any remaining portion of this part of the expansion deposit at the end of the two year warranty period.

3.2.25 Any expansion deposit required under section 3.2.20 shall be in the form of cash, letter of credit from a bank as defined in the Bank Act, or surety bond. The distributor shall allow the customer to select the form of the expansion deposit.

3.2.26 Where any expansion deposit is in the form of cash, the distributor shall return the expansion deposit to the customer together with interest in accordance with the following conditions:

(a) interest shall accrue monthly on the expansion deposit commencing on receipt of the total deposit required by the distributor; and

(b) the interest rate shall be at the Prime Business Rate set by the Bank of Canada less 2 percent.

3.2.27 Unforecasted customers that connect to the distribution system during the five-year customer connection horizon will benefit from the earlier expansion and should contribute their share. In such an event, the initial contributors shall be entitled to a rebate from the distributor. A distributor shall collect from the unforecasted customers an amount equal to the rebate the distributor shall pay to the initial contributors. The amount of the rebate shall be determined as follows:

(a) for a period of up to five years, the initial contributor shall be entitled to a rebate without interest, based on apportioned benefit for the remaining period; and

(b) the apportioned benefit shall be determined by considering such factors as the relative name-plate rated capacity of the generator customers, the relative non-coincident peak demand of the load customers and the relative line length in proportion to the line length being shared by the customers , as applicable.

3.2.27A Notwithstanding section 3.2.27, when the unforecasted customer is a renewable energy generation facility to which section 3.2.5A or 3.2.5B applies and the customer entitled to a rebate under section 3.2.27 is a load customer or a generation customer to which neither section 3.2.5A nor 3.2.5B applies, the initial contributors shall be entitled to a rebate from the distributor in an amount determined in accordance with section 3.2.27. The distributor shall reduce the connecting renewable energy generation facility's renewable energy expansion cost cap by an amount equal to the rebate. If the amount of the rebate exceeds the connecting renewable generation facility's renewable energy expansion cost cap, the distributor shall also collect the difference from the connecting renewable energy generation customer.

3.2.27B Notwithstanding section 3.2.27, when an unforecasted customer that is a renewable energy generation facility to which section 3.2.5A or 3.2.5B applies (the “unforecasted renewable generator”) connects to the distribution system during the customer connection horizon as defined in Appendix B and benefits from an earlier expansion made on or after October 21, 2009 to connect another renewable energy generation facility to which section 3.2.5A or 3.2.5B applies (the “initial renewable generator”), the initial renewable generator shall be entitled to a rebate if the cost of the earlier expansion exceeded the initial renewable generator’s renewable energy expansion cost cap. In such a case, the following rules shall apply:

(a) the distributor shall pay to the initial renewable generator a rebate in an amount determined in accordance with section 3.2.27C; and

(b) the distributor shall collect from the unforecasted renewable generator an amount determined in accordance with section 3.2.27C.

For greater certainty, no rebate shall be payable to an initial renewable generator towards the cost of an earlier expansion if the cost of the earlier expansion did not exceed the initial renewable generator’s energy expansion cost cap.

3.2.27C For the purposes of section 3.2.27B:

(a) the amount of the rebate payable by the distributor to the initial renewable generator shall be the difference between the amount paid by the initial renewable generator towards the cost of the earlier expansion and the amount that would have been paid by the initial renewable generator towards that cost, determined in accordance with the rules set out in sections 3.2.5B and 3.2.5C, had the earlier expansion been undertaken for both the initial renewable generator and the unforecasted renewable generator. The rebate shall be without interest; and

(b) the amount to be collected from the unforecasted renewable generator shall be the amount that would have been paid by the unforecasted renewable generator towards the cost of the earlier expansion, determined in accordance with the rules set out in sections 3.2.5B and 3.2.5C, had the earlier expansion been undertaken for both the initial renewable generator and the unforecasted renewable generator.

3.2.27D Notwithstanding section 3.2.27, an unforecasted customer that is a load customer or a generation customer to which neither section 3.2.5A or 3.2.5B applies, that connects to the distribution system during the customer connection horizon as defined in Appendix B and that benefits from an earlier expansion made on or after October 21, 2009 to connect a renewable generation facility to which section 3.2.5A or 3.2.5B applies (the “initial renewable generator”) shall contribute towards the cost of the earlier expansion. In such a case, the following rules shall apply:

(a) where the cost of the earlier expansion exceeded the initial renewable generator’s renewable energy expansion cost cap, the initial renewable generator and the distributor shall be entitled to a rebate in an amount determined in accordance with sections 3.2.27 and 3.2.27E; or

(b) where the cost of the earlier expansion was at or below the initial renewable generator’s renewable energy expansion cost cap, the distributor shall be entitled to a rebate in an amount determined in accordance with section 3.2.27.

3.2.27E For the purposes of section 3.2.27D(a), the amount of the rebate shall be apportioned between the initial renewable generator and the distributor on a pro-rata basis based on their respective contributions to the cost of the earlier expansion.

3.2.27F For greater certainty:

(a) sections 3.2.27B and 3.2.27D do not apply in respect of an expansion referred to in section 3.2.5A(a) or 3.2.5B(a);

(b) the amount of the rebate payable to an initial renewable generator under section 3.2.27B or section 3.2.27D(a) shall not exceed the amount paid by the initial renewable generator as a capital contribution towards the cost of the earlier expansion; and

(c) where an earlier expansion referred to in section 3.2.27B or 3.2.27D was made to connect more than one renewable energy generation facility to which section 3.2.5B applies, the amount of the rebate payable to the renewable generators shall be apportioned between them on a pro-rata basis based on the total name-plate rated capacity of each renewable energy generation facility referred to in section 6.2.9(a) (in MW).

3.2.28 A distributor shall prepare all estimates and offers required by section 3.2 in accordance with good utility practice and industry standards.

3.2.29 The distributor shall perform all of its responsibilities and obligations under section 3.2 in a timely manner.

3.2.30 An expansion of the main distribution system includes:

(a) building a new line to serve the connecting customer;

(b) rebuilding a single-phase line to three-phase to serve the connecting customer;

(c) rebuilding an existing line with a larger size conductor to serve the connecting customer;

(d) rebuilding or overbuilding an existing line to provide an additional circuit to serve the connecting customer;

(e) converting a lower voltage line to operate at higher voltage;

(f) replacing a transformer to a larger MVA size;

(g) upgrading a voltage regulating transformer or station to a larger MVA size; and

(h) adding or upgrading capacitor banks to accommodate the connection of the connecting customer.

3.3 Enhancements

3.3.1 A distributor shall continue to plan and build the distribution system for reasonable forecast load growth. A distributor may perform enhancements to its distribution system for purposes of improving system operating characteristics or for relieving system capacity constraints. In determining system enhancements

APPENDIX B

Methodology and Assumptions for

An Economic Evaluation

Last Revised October 21, 2009

APPENDIX B - METHODOLOGY AND ASSUMPTIONS FOR AN OFFER TO CONNECT ECONOMIC EVALUATION

B.1 COMMON ELEMENTS OF THE DISCOUNTED CASH FLOW MODEL

To achieve consistent business principles for the development of the elements of an economic evaluation model, the following parameters for the approach are to be followed by all distributors.

The discounted cash flow (DCF) calculation for individual projects will be based on a set of common elements and related assumptions listed below.

Revenue Forecasting

The common elements for any project will be as follows:

(a) Total forecasted customer additions over the Customer Connection Horizon, by class as specified below;

(b) Customer Revenue Horizon as specified below;

(c) Estimate of average energy and demand per added customer (by project) which reflects the mix of customers to be added - for various classes of customers, this should be carried out by class;

(d) Customer additions, as reflected in the model for each year of the Customer Connection Horizon; and

(e) Rates from the approved rate schedules for the particular distributor reflecting the distribution (wires only) rates.

Capital Costs

Common elements will be as follows:

(a) An estimate of all capital costs directly associated with the expansion to allow forecast customer additions.

(b) For expansions to the distribution system, costs of the following elements, where applicable, should be included:
- distribution stations;
- distribution lines;
- distribution transformers;

- secondary busses;
- services; and
- land and land rights.

Note that the “Ownership Demarcation Point” as specified in the distributor’s Condition of Service would define the point of separation between a customers’ facilities and distributor’s facilities.

(c) Estimate of incremental overheads applicable to distribution system expansion.

(d) A per kilowatt enhancement cost estimate – the per kilowatt enhancement cost estimate shall be set annually and shall be based on a historical three to five year rolling average of actual enhancement costs incurred in system expansions.

(d.1) paragraph (d) shall cease to apply to a distributor as of the date on which the distributor’s rates are set based on a cost of service application for the first time following the 2010 rate year.

(e) For residential customers, the amount the cost of the basic connection referred to in section 3.1.4 of the Code.

(f) For non-residential customers, if the distributor has chosen to recover the non-residential basic connection charge as part of its revenue requirement, a description of, and the amount for, the connection charges referred to in section 3.1.5 of the Code that have been factored into the economic evaluation.

Expense Forecasting

Common elements will be as follows:

(a) Attributable incremental operating and maintenance expenditures - any incremental attributable costs directly associated with the addition of new customers to the system would be included in the operating and maintenance expenditures.

(b) Income and capital taxes based on tax rates underpinning the existing rate schedules.

(c) Municipal property taxes based on projected levels.

Specific Parameters/Assumptions

Specific parameters of the common elements include the following:

(a) A maximum customer connection horizon of five (5) years, calculated from the energization date of the facilities.[1]

(b) A maximum customer revenue horizon of twenty five (25) years, calculated from the in service date of the new customers.[2]

(c) A discount rate equal to the incremental after-tax cost of capital, based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity.

(d) Discounting to reflect the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted. The same approach to discounting will be used for revenues and operating and maintenance expenditures.[3]

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[1] For customer connection periods of greater than 5 years an explanation of the extension of the period will be provided to the Board

[2] For example, that the revenue horizon for customers connected in year 1, is 25 years while for those connected in year 3, the revenue horizon is 22 years.

[3] For certain projects Capital Expenditures may be staged and can occur in any year of the five year Connection Horizon.

B.2 DISCOUNTED CASH FLOW (DCF) METHODOLOGY

Net Present Value ("NPV")	=	Present Value ("PV") of Operating Cash Flow + PV of CCA Tax Shield - PV of Capital
1. PV of Operating Cash Flow	=	P V of Net Operating Cash (before taxes) - P V of Taxes
a) PV of Net Operating Cash	=	PV of Net Operating Cash Discounted at the Company's discount rate for the customer revenue horizon. Mid-year discounting is applied. Incremental after tax weighted average cost of capital will be used in discounting.
Net (Wires) Operating Cash	=	(Annual(Wires) Revenues - Annual (Wires) O&M)
Annual (Wires) Revenue	=	Customer Additions * [Appropriate (Wires) Rates * Rate Determinant]
Annual (Wires) O&M	=	Customer Additions * Annual Marginal (Wires) O&M Cost/customer
b) PV of Taxes	=	PV of Municipal Taxes + PV of Capital Taxes + PV of Income Taxes (before Interest tax shield)
Annual Municipal Tax	=	Municipal Tax Rate * (Total Capital Cost)
Total Capital Cost	=	Distribution Capital Investment + Customer Related Investment + overheadsd at the project level
Annual Capital Taxes	=	(Capital Tax Rate) * (Closing Undepreciated Capital Cost Balance)
Annual Capital Tax	=	(Capital Tax Rate) * (Net Operating Cash - Annual Municipal Tax B Annual Capital Tax)

The Capital Tax Rate is a combination of the Provincial Capital Tax Rate and the Large Corporation Tax (Grossed up for income tax effect where appropriate).

Note: Above is discounted, using mid-year discounting, over the customer revenue horizon.

2. PV of Capital	=	P V of Total Annual Capital Expenditures

a) PV of Total Annual Capital Expenditures

Total Annual Capital Expenditures over the customer's revenue horizon discounted to time zero

Total Annual Capital Expenditure	=	(for New Facilities and/or Reinforcement Investments + Customer Specific Capital + Overheads at the project level). This applies for implicated system elements at the utility side of the “Ownership Demarcation Line”.

Note: Above is discounted to the beginning of year one over the customer addition horizon

3. PV of CCA Tax Shield

P V of the CCA Tax Shield on [Total Annual Capital]

The PV of the perpetual tax shield may be calculated as:

PV at time zero of: $$\frac{[(\text{Income tax Rate}) * (\text{CCA Rate}) * \text{Annual Total Capital}]}{(\text{CCA Rate} + \text{Discount Rate})}$$

or,

Calculated annually and present valued in the PV of Taxes calculation.

Note: An adjustment is added to account for the ½ year CCA rule.

4. Discount Rate

PV is calculated with an incremental, after-tax discount rate.