ENBRIDGE GAS INC. 2024 REBASING APPLICATION – PHASE 2

EB-2024-0111

ONTARIO ENERGY BOARD STAFF INTERROGATORIES

1.7-Staff-1

Ref: EB-2022-0200, Decision and Order, p. 135

In Phase 1, the OEB denied Enbridge Gas's exemption request to change the MRPM metric to 2.0% of meters (from the current 0.5% metric).

In that decision, the OEB stated:

> Enbridge Gas needs to improve its performance rather than seek to change the metric. It is imperative that customers have accurate bills to manage their expenses, assess their energy costs and manage their energy activities accordingly. Changing the metric to 2% would lock in the adverse performance levels that occurred in unusual circumstances. The OEB finds that there are no unusual circumstances persisting in 2023, beyond Enbridge Gas's control.

a) Please describe how Enbridge Gas has considered the OEB's decision in Phase 1, related to the MRPM exemption request, in its current proposal to exclude inaccessible meters from MRPM calculations.

1.7-Staff-2

Ref: Exhibit 7, Tab 1, Schedule 1, p. 6 and Attachment 2

Enbridge Gas is proposing that all meters with access issues caused by or within the control of the customer to address be excluded from the Meter Reading Performance Metric (MRPM) calculation for the purposes of the scorecard measure, starting January 2024 for the entirety of the IR term.

Enbridge Gas provided the number of consecutive estimated meters attributable to inaccessible meters and the MRPM calculation with and without inaccessible meters removed for 2022 and 2023 and the forecast for 2024.

Attachment 2 is reproduced below:

	Total number of consecutive estimate meters	% of Target Achieved	Total number of inaccessible meters
2022	1,906,081	4.10%	613,431
2023	614,305	1.31%	302,789
2024 (forecast)	502,664	1.06%	247,372

a) Please describe the approach taken to inform Enbridge Gas staff of any known difficult locations including whether this information is recorded in the customer information or other systems that can be accessed by meter readers.
b) Please confirm that Enbridge Gas would not include unusual circumstances outside of both the customer and Enbridge Gas's control (i.e., extreme weather, global pandemic, etc.) as part of the number of inaccessible meters for the purposes of calculating the MPRM metric.
c) Please provide the number of consecutive estimated meters attributable to inaccessible meters and the MRPM calculation with inaccessible meters removed from 2019 to 2021. Please discuss any trends in the data.
d) Please explain why Enbridge Gas is proposing to exclude inaccessible meters from its MRPM calculations when its number of consecutive estimate meters and number of inaccessible meters have decreased significantly from 2022 and are forecasted to continue to decrease, with the MRPM target improving since 2022.
e) Please provide rationale for Enbridge Gas's proposal to exclude inaccessible meters from its MRPM calculations for the entire IR term (i.e., instead of requesting an exemption in each IR year, as applicable).
f) Please provide the last 10 years, for each year, quantities of inaccessible meters broken up by:
    i. Customer caused versus non-customer caused
        i. If sub-causes exist, provide with that resolution as well
    ii. Rate Zone (EGD, Union South, Union North East, Union North West)
    iii. Total meters

Please use the following table as an example:

Category		2015	…..	2024
Customer Caused	Total			
	Rate Zone			
Non-Customer Caused	Total			
	Rate Zone			
Total Meters	Total			
	Rate Zone			

g) Please provide the average meter read times for inaccessible meters in 2023 due to:
   i. Customer reasons
   ii. Non-customer reasons

1.7-Staff-3

Ref: Exhibit 1, Tab 7, Schedule 1, p. 7

In its evidence, Enbridge Gas has indicated that if the Ontario Energy Board (OEB) were to take a strict view of the Meter Reading Performance Measurement (MRPM) metric and not accept its proposal to remove inaccessible meters from the calculation of unread meters, Enbridge Gas may need to conduct additional service disconnections just to have a better chance of meeting the MRPM. Enbridge Gas further noted that such an approach would be inefficient and would not be in the best interest of customers.

a) Please describe the rationale for the need to conduct additional service disconnections in order to meet the MRPM.
b) If Enbridge Gas proceeds with additional service disconnections, what would be the basis and process for disconnecting a customer whose meter is inaccessible?
c) Does Enbridge Gas visit the customer at the premises and show the customer the inaccessible meter and discuss options?
d) In cases where there is an obstruction, has Enbridge Gas considered the possibility of clearing the obstruction with the permission of the customer (clearing vegetation, trimming etc.)?

1.10-Staff-4

Ref: Exhibit 1, Tab 10, Schedule 7, pp. 1-11

Enbridge Gas requests approval of an Energy Transition Technology Fund (ETTF) and provides a rationale for and description of the proposed ETTF.

a) Enbridge Gas notes (p. 5) that it will prioritize technology innovation initiatives that: reduce GHG emissions; provide safe, reliable and affordable low-carbon options for customers; are outside of those needs already funded through demand side management; are compliant with industry codes and standards; range from pre-commercial to commercial activities; and cover residential, commercial, and industrial sectors, with appropriate pace of commercialization timeline.
   Is this a complete list of the criteria Enbridge Gas will use to evaluate potential initiatives and determine how to allocate ETTF funding? Has Enbridge Gas developed a scoring methodology to compare and rank potential initiatives?
b) Please describe what performance metrics and reporting Enbridge Gas will use to assess and report on the effectiveness of its ETTF spending.
c) Many of the proposed ETTF areas of technology innovation (pp. 5-8) do not directly relate to activities that Enbridge Gas can currently undertake as part of its regulated utility business (e.g., utilization of captured carbon dioxide to create higher value products). Does Enbridge Gas believe that the degree to which the regulated utility business will be the direct beneficiary of the learnings from the ETTF is relevant to decisions on which technologies to fund? Why or why not?
d) Does Enbridge Gas have any hydrocarbon production facilities? If yes, how much is produced per year?
e) How is Enbridge Gas more suited for Carbon Capture research versus Enbridge Inc.?
f) How do rate payers obtain value for research paid for by them, but performed by Enbridge Gas, which is then applied to Enbridge Inc.? How does Enbridge Gas propose to track this value for rate payers and how will Enbridge Inc. pay back this value to Ontario rate payers?
g) From paragraph 15 in Section 2.1, is Enbridge Gas proposing to begin production of hydrocarbons through the “support [of] further development of alternative technologies such as gasification to enable access to a variety of feedstocks (e.g., agriculture waste, forestry residues, municipal solid waste), thus increasing supply, and over time, lowering cost”? If no, why should rate payers be paying to expand Enbridge Gas into the new field of hydrocarbon development? (Note: RNG is hydrocarbon production)

h) Why should Ontario rate payers pay for Enbridge Gas to expand into hydrogen production? How does this meet a business requirement for gas distribution versus simply adding a new area of business?
i) For Section 2.2 why should Enbridge Gas be leading the research in end-use equipment versus other business and entities? Is this an appropriate avenue of investment for Ontario distribution rate payers? In consideration of the use of blended hydrogen and natural gas in Europe why should Ontario rate payers be paying for additional research and development in end-use equipment which is an established industry outside North America?

1.13-Staff-5

Ref: Exhibit 1, Tab 13, Schedule 4, p. 2.

In its evidence, Enbridge Gas noted that the Dawn to Corunna Replacement Project does not create any incremental storage capacity, withdrawal capability or injection capability. By applying either the storage cost allocation methodology in place at the time of project approval or the harmonized storage cost allocation methodology, the result according to Enbridge Gas is that 100% of the project costs should be allocated to regulated operations.

a) Please confirm that the unregulated storage operations have not benefitted in any manner as a result of the Dawn to Corunna Replacement Project. If yes, please explain the benefits.
b) The Dawn to Corunna pipeline and associated station work at the Corunna Compressor Station and the Dawn Operations Centre to connect the new pipeline to the existing facilities maintains withdrawal and injection capability and working capacity at the Dawn Hub. Please confirm if any of the existing services that continued to be maintained as a result of the Dawn to Corunna Replacement Project were provided to the unregulated storage operations. If yes, please explain.
c) Were there any non-regulated storage OM&A dollars associated to the compressors at Corunna which are being abandoned? If so, how are rate payers getting value from the reduction in non-regulated OM&A costs considering the new pipeline to achieve those cost savings are all regulated capital?

1.13-Staff-6

Ref: Exhibit 1, Tab 13, Schedule 4, Attachment 1, p. 2

The amalgamation of Enbridge Gas Distribution (EGD) and Union Gas provided Enbridge Gas with the opportunity to operate the storage systems as a single utility. The storage system associated with the Enbridge Gas storage pools is allocated to three categories: Union Gas rate zones, EGD rate zone and Enbridge Gas non-utility. The Enbridge Gas storage system contains 35 storage pools. Each storage pool has unique characteristics and an associated amount of storage space and deliverability.

a) Please provide the daily withdrawal data from the combined Union and EGD storage facilities beginning in 2005 until the end of April 2024 broken down between in-franchise receipts, other Ontario gas utilities, and non-utility customers.
b) Please provide a table listing each of Enbridge Gas's 35 storage pools and the following information broken down as follows:
    i. Total working storage capacity of each pool
    ii. The portion of working storage capacity in each pool developed under rate base
    iii. The portion of maximum withdrawal capability of each pool developed under rate base
    iv. The years and application numbers related to the development of the working storage capacity and withdrawal capability (including incremental expansion) under rate base for each pool
    v. The portion of working storage capacity in each pool developed for unregulated storage services
    vi. The portion of maximum withdrawal capability of each pool developed for unregulated storage services
    vii. The years and application numbers related to the development of the working storage capacity and withdrawal capability of each pool for unregulated storage services
c) Please provide the cost per GJ for providing storage services to in-franchise bundled service customers under the proposed 2024 forecast.

1.13-Staff-7

Ref: Exhibit 1, Tab 13, Schedule 4, Attachment 2

Enbridge Gas filed the Dawn to Corunna Replacement Post Construction Financial Report at the above reference.

a) In Table 2, please add a column showing actual contract final cost. Please provide the change orders which created those deltas between actual and bid cost and the approvals for those change orders.
b) In Section 3.2 – Enbridge Gas identifies $8 million of increased project cost due to incorrect records (depth of NPS 42 pipe). Please confirm if the NPS 42 pipe is rate regulated or non-rate regulated. What was identified as the issue of the incorrect records, as 2.5 meters is a significant vertical underground distance?

   i. Why is the cost report in this section different than 4.6?

c) In Section 4, please detail which costs would typically fall under contingency and how much for each table and category. For example – 4.4 Facilities, Valves and Fittings – increases in valve and fitting quantities due to detailed design is a basic construction project expectation and is typically covered by contingency.
d) In Appendix B, why was the average rainfall from 1981 to 2010 used? Why were those years chosen? What is the average rainfall from 2009-2018?
e) In Appendix B, for the 2023 period, what was the average rainfall of Sarnia Airport and Petrolia Town?
f) How is the cost variance of this project being incorporated into Enbridge Gas's estimation techniques and proper contingency levels to be used?

1.16-Staff-8

Ref: Exhibit 1, Tab 16, Schedule 1, pp. 1-2, 20

Enbridge Gas indicates that its energy comparison information is used to create printout and digital marketing materials to inform potential conversion customers and other third-party stakeholders with respect to potential new conversion attachments, and to support stakeholder briefings such as for the OEB, government, and the HVAC industry. Enbridge Gas indicates that this information estimates heating bills for conversions from three standard existing energy sources (i.e., heating oil, propane, and electric resistance heating) to natural gas (pp. 1-2). Enbridge Gas also indicates that it has determined that the current energy comparison chart is most applicable to conversion customers and will no longer be shared with builders (p. 20).

a) Please describe the specific marketing materials and circumstances in which potential conversion customers would be presented with this energy comparison information. In particular, does Enbridge Gas create any marketing materials using this energy comparison information that is proactively pushed out to target businesses or individuals who are not Enbridge Gas customers (e.g., web ads, mail-outs, etc.), or are these materials only available if contact is initiated by these individuals or businesses (e.g., visit to Enbridge Gas website, phone call to Enbridge Gas)?
b) Does the marketing approach differ between community expansion project areas and other parts of Ontario?
c) How does Enbridge Gas ensure that, when used in stakeholder briefings, use of these materials is limited to the context of providing information with respect to potential conversions to natural gas from these standard existing energy sources?
d) Are any informational materials based on this energy comparison information provided to existing Enbridge Gas customers (e.g., bill inserts, or sections of

website intended for existing customers)? If so, please describe these materials, and indicate the purpose of providing this information to existing customers.

1.16-Staff-9

Ref: Exhibit 1, Tab 16, Schedule 1, pp. 4-6

Enbridge Gas describes why its information sheets do not illustrate a consumer energy equivalent annual heating bill for conversions from certain energy sources, including electric heat pumps. Enbridge Gas indicates (p. 6) that “providing consumer conversion cost information related to conversions to electric ccASHPs without consideration of the electric supply-side requirements and implications within the relevant area would not be appropriate. Supply-side requirements, including the costs required to generate, transmit, and distribute electricity, are critical factors with respect to a community’s energy security/reliability.”

Does Enbridge Gas seek to limit conversions to natural gas in areas where facility reinforcement of the gas system may be needed (e.g., as identified through Enbridge Gas’s Asset Management Plan/System Reinforcement Plan)? If not, please clarify why Enbridge Gas believes that this perspective on supply-side costs is important for electricity, whereas for natural gas, the end-user costs from the consumer perspective are sufficient.

1.16-Staff-10

Ref: Exhibit 1, Tab 16, Schedule 1, p. 20

Enbridge Gas indicates that it has determined that the current energy comparison chart is most applicable to conversion customers and will no longer be shared with builders. When builders or developers request this information, Enbridge Gas will direct them to contact an HVAC provider.

Please describe how Enbridge Gas plans to communicate and incorporate this change into its internal operational procedures and practices (e.g., natural gas service application process, other points of contact with the development community).

1.16-Staff-11

Ref: Exhibit 1, Tab 16, Schedule 1, pp. 20-22, plus Attachment 1, 2

Enbridge Gas describes its 2023 and 2024 reviews and updates of its energy comparison information.

Enbridge Gas notes that, as a result of its 2024 review, the term 'electricity' was replaced with the term 'electric resistance' on the bar label of the energy comparison information to provide enhanced clarity, along with some other text updates to the disclaimer. These updates are reflected in the energy comparison information produced for its April 2024 QRAM update (Attachment 2).

Enbridge Gas further indicates that the "cost calculator tool" was removed from the Community Expansion pages of enbridgegas.com and all references to it removed from marketing messaging.

a) Is the "cost calculator tool" a reference to the graphic shown on Attachment 1, page 12, or something else?
b) If the latter, does a graphic such as that shown on Attachment 1, page 12 remain in the current Community Expansion marketing package, and if so, has Enbridge Gas made the same updates that it has made to the energy comparison information produced for its April 2024 QRAM update (Attachment 2)?

1.17-Staff-12

Ref: Exhibit 1, Tab 17, Schedule 1, pp. 4-8; IRP Decision and Order, July 22, 2021, pp.56-57

Enbridge Gas describes the replacement versus asset life extension considerations that it will consider in an Asset Life Extension (ALE) analysis.

a) Does Enbridge Gas expect that the methodology for the ALE analysis will be similar to the enhanced Discounted Cash Flow-Plus test that Enbridge Gas will use to compare the costs and benefits of Integrated Resource Planning (IRP) initiatives with a facility solution, under the IRP Framework? Please describe any key methodological differences Enbridge Gas anticipates, and whether the new proposed considerations of energy transition sensitivity analysis and stranded asset risk are expected to be common to both analyses.
b) The OEB has directed Enbridge Gas to develop and file an enhanced Discounted Cash Flow-Plus test for OEB approval. Does Enbridge Gas believe the methodology for the ALE analysis should require approval by the OEB (either as part of approval of the Discounted Cash-Flow Plus test, or separately)? Why or why not?
c) Please confirm that Enbridge Gas's ALE analysis for specific ALE projects would be filed as part of an ICM application, to demonstrate prudence.

1.17-Staff-13

Ref: Exhibit 1, Tab 17, Schedule 1, pp. 6-7

Enbridge Gas describes its proposed approach to evaluating and identifying ALE alternatives.

Procedurally, where in the evaluation process does Enbridge Gas's approach to evaluating and identifying ALE alternatives fit with respect to Enbridge Gas's approach to evaluating and identifying IRP alternatives, in identifying the best overall option to address a system need (e.g., will assessments of ALE and IRP alternatives be done in parallel, will one precede the other, are they combined in any fashion)?

1.17-Staff-14

Ref: Exhibit 1, Tab 17, Schedule 1, pp. 8-9

Enbridge Gas states the reliability results for the Enhanced Distribution Integrity Management Program (EDIMP) pipelines will be compared with industry targets using CSA Z662 Annex O as an example.

a) Please explain why Annex O being used for a non-transmission line. Enbridge Gas has stated EDIMP lines will be distribution lines (less than 30% SMYS).

1.17-Staff-15

Ref: Exhibit 1, Tab 17, Schedule 1, pp. 10-11

Enbridge Gas provides examples of capital and O&M spending associated with ALE measures.

a) Please describe how Enbridge Gas's existing capitalization policy has informed Enbridge Gas's determination as to which ALE measures would be capital spending and which would be O&M.
b) Does Enbridge Gas believe any determination by the OEB as to which ALE measures are eligible to be capitalized is necessary, or is there sufficient clarity regarding the accounting treatment for this category of activities (e.g., within Enbridge Gas's capitalization policy, or previous OEB determinations)? Please describe as needed.

1.17-Staff-16

Ref: Exhibit 1, Tab 17, Schedule 1, pp. 11-16

Commencing in 2024, the EDIMP is a newly established part of the Distribution Integrity Management Program (DIMP) subprogram that expands the condition monitoring of operationally critical, higher stress steel distribution pipelines. Enbridge Gas currently performs ALE work as part of its day-to-day operations which is recovered in rates. However, the additional ALE work that Enbridge Gas is proposing to undertake through the EDIMP could result in additional ALE projects that would impact the timing, type and magnitude of annual O&M and capital expenditures.

In its application, Enbridge Gas has proposed a change to the criteria to determine Incremental Capital Module (ICM) eligibility for ALE alternatives resulting from EDIMP. Enbridge Gas has proposed to exclude the $10 million in-service capital addition requirement and set this to zero dollars for ALE alternatives. Enbridge Gas has also proposed a grouping of ALE alternatives to pursue multiple, smaller ALE alternatives in a single ICM request in years where Enbridge Gas's capital budget exceeds the materiality threshold.

a) Please explain why spending on ALE alternatives cannot be accommodated in the approved capital budget considering that spending on extending the life of assets avoids spending on replacement that is currently included in the capital budget.
b) Please describe how Enbridge Gas intends to assure the OEB that recovery of ALE alternatives through ICM does not result in double recovery, once through the capital budget and again through the ICM rate rider.
c) Please provide evidence that the approved capital budget is not sufficient to pursue ALE alternatives through the maintenance expenditures approved in the budget or through the avoided spend on replacement programs that were approved in the capital budget.

1.17-Staff-17

Ref: Exhibit 1, Tab 17, Schedule 1, p.13, pp. 19-21

Enbridge Gas proposes that capital expenditures related to ALE alternatives be eligible for recovery via the ICM. Enbridge Gas also discusses the approach to cost recovery of IRP costs under the IRP framework, and notes the IRP Framework's determination that it was premature to develop an incentive mechanism or offer additional incentives, and that incentives could be explored as part of a future IRP Plan as experience and lessons are gained.

a) The proposed approach for recovery of ALE capital costs differs from that approved for IRP alternatives, in which the IRP Capital Costs Deferral Account records the actual annual revenue requirement of project costs eligible to be capitalized for inclusion in rate base, with an offset for revenue requirement already included in rates related to facilities that are delayed, avoided, or downsized by an IRP Plan. Is Enbridge Gas of the view that the approach it has proposed for recovery of ALE capital costs better achieves the objective of incentivizing Enbridge Gas to implement economic alternatives to gas infrastructure than the approach used for cost recovery for IRP alternatives? Why or why not?

b) Has Enbridge Gas given further consideration to requesting IRP-related incentives as part of an IRP Plan, including consideration of incentive mechanisms based on the OEB's Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives, or other approaches to incentives? If so, please describe the status of Enbridge Gas's review.
c) Did Enbridge Gas give any consideration to broader changes associated with the incentive rate-setting mechanism, as a means of achieving the objective of incentivizing Enbridge Gas to implement economic alternatives to gas infrastructure? If so, please describe Enbridge Gas's analysis and findings, and provide Enbridge Gas's rationale as to why its proposal for cost recovery of ALE costs is the preferred means of achieving this objective.

1.17-Staff-18

Ref: Exhibit 1, Tab 17, Schedule 1, p.17

Enbridge Gas notes that ALE alternatives that result in O&M expenditures will be recorded in the DIMP Variance Account (in addition to the O&M costs associated with ALE analysis, risk evaluation and assessment).

Is Enbridge Gas's understanding that the use of the DIMP Variance Account for O&M costs associated with implementation of ALE alternatives (as differentiated from O&M costs related to the DIMP and Enhanced DIMP programs themselves) was considered by parties as part of the Phase 1 settlement and is consistent with the Phase 1 settlement agreement?

1.17-Staff-19

Ref: Exhibit 1, Tab 17, Schedule 1, p. 23, 26; IRP Decision and Order, July 22, 2021, p.35

Enbridge Gas notes that it is not submitting a specific system pruning proposal in Phase 2. Enbridge Gas is, instead, proposing to engage the IRP Technical Working Group (TWG) and other relevant stakeholders in a collaborative process to determine if there is a technically and economically feasible system pruning IRP pilot to pursue and, if so, develop, together with the electric sector, a system pruning pilot. Enbridge Gas further notes its understanding that the more recent Phase 1 Decision supersedes the existing decision from the first-generation IRP Framework and signals that piloting electric measures would be an effective way to understand how the IRP Framework could be evolved.

a) Does Enbridge Gas request the OEB to confirm that the scope of pilot consideration could potentially include providing funding to Enbridge Gas for electricity IRPAs (i.e.. superseding the language on p. 35 of the IRP decision that notes that "…as part of this first-generation IRP Framework, the OEB has determined that it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs"?
b) If so, does Enbridge Gas request the OEB to confirm that the options Enbridge Gas could consider for funding electricity IRPAs could include the ability to own and rate base assets associated with electricity IRPAs?
c) In what manner does Enbridge Gas propose to report back to the OEB on the results of its assessment regarding a system pruning pilot? Does Enbridge Gas propose a firm date for this report back?

1.18-Staff-20

Ref: Energy Sustain, Exhibit 1, Tab 18, Schedule 1, p. 1

Enbridge Sustain is a registered business name and an unregulated line of business carried on by Enbridge Gas.

Please provide the date of registering the Enbridge Sustain business name and the date on which Enbridge Sustain started providing service to customers.

1.18-Staff-21

Ref: Exhibit 1, Tab 18, Schedule 1, p. 4

Enbridge Gas notes that support services are provided to Enbridge Sustain by other Enbridge Gas staff members in areas such as legal, supply chain, finance, information technology and human resources. Enbridge Gas employees who are providing support services directly to Enbridge Sustain track their time and related costs are treated as 100% non-utility and are charged to the Enbridge Sustain unregulated line of business.

Please confirm that the system and process used to track time of Enbridge Gas employees is the same as that used to track the time for services provided to other Enbridge Inc. affiliates.

4.2-Staff-22

Ref: Exhibit 4, Tab 2, Schedule 1, pp. 16

Enbridge Gas has proposed a total in-franchise storage requirement of 227.7 PJ for 2024. Enbridge Gas noted that it is confident that the proposed in-franchise storage requirement of 227.7 PJ reflects the appropriate balance of cost and risk and results in a Gas Supply Plan that is reliable, operationally flexible and cost effective.

Please provide the actual annual storage capacity that was required to meet the needs of in-franchise customers from 2019 to 2023.

4.2-Staff-23

Ref: Exhibit 4, Tab 2, Schedule 1, Attachment 2, Addendum to the ICF Report, p. 8

In the Addendum to the October 2022 ICF Report, ICF has provided a bar chart (Exhibit 2-3) showing the difference between winter and summer prices at Dawn in ICF Q4 2023 base case versus ICF Q2 2022 base case.

Please provide a comparison of the forecasted Dawn prices in Exhibit 2.3 for the 2024 to 2029 period with the Henry Hub futures pricing, using the bar chart format, for the same period as at the date of the creation of Exhibit 2.3 in the February 2024 study.

4.2-Staff-24

Ref: Exhibit 4, Tab 2, Schedule 1, Attachment 2, p. 27

In the Addendum to the October 2022 ICF Report, ICF has indicated that the normal weather scenario reflects the average weather patterns over a 20-year period from 2003-2022 and that it underestimates the volatility associated with actual weather.

Please identify the original source of the temperature data used in the ICF studies and the location(s) where the temperatures were recorded.

4.2-Staff-25

Ref: Exhibit 4, Tab 2, Schedule 1, Attachment 2, p. 40

In the Addendum to the October 2022 ICF Report, ICF has provided a scatter plot of Enbridge Gas Storage Contracts' Unit Rate and Deliverability and a regression analysis to identify storage value (Exhibit A-1).

a) Please confirm that the outliers removed in the regression analysis shown in Exhibit E1 of the 2022 ICF Report were also removed in Exhibit A1 of the 2024 Update.
b) Please explain why two deliverability outliers in Exhibit A1 were retained. Would 8% and 10% deliverability not also be considered outliers when compared to storage services more appropriately designed for typical in-franchise bundled service customers?
c) Please produce the results of your regression analysis with those outliers removed and the impact that would have on your cost of the market-based

services and delivered services estimated in this updated report and the cost effectiveness of these alternatives to that analysis.

4.2-Staff-26

Ref: Exhibit 4, Tab 2, Schedule 1, Attachment 3, p. 4

In Footnote 2 of the October 2022 ICF Report, it indicates that 185 PJ of storage capacity for bundled service customers is utility owned and provided at the cost of service.

Please confirm that ICF relied on the storage volume available to in-franchise bundled service customers provided to it by Enbridge Gas and did not undertake their own analysis of what that volume should be.

4.2-Staff-27

Ref: Exhibit 4, Tab 2, Schedule 1, Attachment 3, p. 5

In the October 2022 ICF Report, it states that "ICF used the Enbridge Gas forecast of natural gas demand".

a) Was ICF instructed by Enbridge Gas to use their forecast of natural gas demand for use in their analysis? Why did ICF not assess the impact of changes in Enbridge Gas in-franchise customer demand on the value of storage?

b) Referring to the observation in the ICF 2022 Report that "EGI[1] assumed each 10 PJ tranche was 5% more expensive than EGI's most recent market-based storage contract", would ICF have made this same assumption given its knowledge of the North American gas markets? If so, why?

c) With respect to the observation in the ICF 2022 Report that Enbridge Gas "assumed the contracting parameters similar to existing physical storage services contracted by Enbridge Gas in recent years with 1.2% maximum deliverability and 0.75% maximum injectability.", what would be the effect on the results if the assumption was changed to reflect a 2.1% maximum deliverability and a 0.85% maximum injectability?

[1] EGI and Enbridge Gas is the same entity.

4.2-Staff-28

Ref: Exhibit 4, Tab 2, Schedule 1, Attachment 3, Page 6 of 71

In the October 2022 ICF Report, ICF assessed the results of Enbridge Gas fixing the level of incremental storage capacity at different levels for one weather scenario to confirm the results of the optimization analysis.

Would ICF have done the analysis differently? Can ICF confirm having done a similar analysis using their own choice of levels of incremental storage capacity for a client?

4.2-Staff-29

Ref: Exhibit 4, Tab 2, Schedule 1, Attachment 3, p. 7

In the October 2022 ICF Report, ICF states "However, in the near term, changes in North American weather patterns are an important driver of storage value."

With respect to that observation please provide a regression analysis comparing daily average temperatures for Toronto during the Typical Weather scenario 2008-2012 period with the daily Dawn Price.

4.2-Staff-30

Ref: Exhibit 4, Tab 2, Schedule 1, Attachment 3, p. 11

In the October 2022 ICF Report, ICF states ""However, the storage market does not operate in a world with perfect foresight into weather and gas market conditions. In addition, market-based storage capacity cannot efficiently be contracted and de-contracted on a year-by-year basis."

a) Given that observation, why undertake scenarios that pick five-year tranches? Please provide evidence that this methodology has been applied elsewhere to specifically support the determination of storage allocation between in-franchise bundled service customers and market-based storage customers.

b) Why would using a 20-year actual weather scenario not be a reasonable approach given this observation, and the provision of storage services to in-franchise bundled services customers who are not in the business to arbitrage or speculate on how natural gas prices are going to behave in a volatile environment?

4.2-Staff-31

Ref: Exhibit 4, Tab 2, Schedule 1, Attachment 3, p.13

In the October 2022 ICF Report, the observation that future storage for bundled service customers is “based on projected natural gas demand growth within this customer group”.

Given that observation, please provide the consumption data for the past 10 years of Enbridge Gas’s bundled service customer group (separately for EGD and Union Gas prior to amalgamation).

4.2-Staff-32

Ref: Exhibit 4, Tab 2, Schedule 7, p.3 and p. 12

Enbridge Gas has proposed cost recovery for low-carbon energy through a newly proposed Low-Carbon Voluntary Program (LCVP) for large volume sales service customers and through the cost of gas supply commodity purchases. Enbridge Gas expects to offer the LCVP on a voluntary basis to large volume sales service customers beginning January 1, 2027. Enbridge Gas plans to procure up to one percent of the equivalent forecast supply requirements as low-carbon energy for 2026 and increase target procurement by one percentage point annually until 2029, reaching four percent.

a) Please indicate the level of interest from large volume sales service customers to purchase low carbon energy and what are the expected volumes that these customers are likely to purchase as part of the LCVP.
b) What is the estimated percentage of low carbon energy volumes that will be purchased by large volume sales service customers in 2027, 2028 and 2029?
c) How does the energy content differ from the typical natural gas supplies versus the RNG? What is the hydrocarbon composition of the RNG?
d) How Enbridge Gas set the 1% target for 2026 to 4% in 2029 considering that current participation is less than 0.2% of total customers?
e) Of the current voluntary program, how much of the voluntary RNG gas consumption makes up of total gas consumption across the entire network for each of the past three years?
f) Is Enbridge Gas proposing a linear increase in voluntary program uptake with increased marketing spend? Please show the projections for voluntary uptake numbers (both customer count and consumption) and marketing spend between 2024-2029. Please show how those projections align with the proposed RNG limits for 2026 to 2029.

g) Are Ontario rate payers allowed to purchase gas from any marketer at this time? Why should rate payers provide additional funds for Enbridge Gas to compete against these other gas marketers? If a demand for RNG was so pronounced, would this not suggest that one of the freely competitive marketers be able to fulfill this market place?

4.2-Staff-33

Ref: Exhibit 4, Tab 2, Schedule 7, p. 7

Enbridge Gas describes the two potential situations where it would stop procuring low carbon energy for a program year, which include a target percentage of low-carbon energy in the total gas supply portfolio, and a maximum bill impact threshold.

a) Please confirm that the target percentage of low-carbon energy in the gas supply portfolio would be calculated on an energy equivalent basis, not a volumetric basis.
b) Please confirm that Enbridge Gas is proposing that the maximum bill impact threshold is tied to the target percentage of low-carbon energy purchases, not the actual percentage of low-carbon energy purchases, and provide Enbridge Gas's rationale for this approach. For example, if Enbridge Gas's target of low-carbon energy purchases is 4% of Enbridge Gas's planned gas supply commodity portfolio, but it only ends up purchasing a supply of low-carbon energy equivalent to 3% of the planned gas supply commodity portfolio, OEB staff's interpretation of Enbridge Gas's proposal is that Enbridge Gas would have the ability to spend up to a level such that the bill impact on residential customers of purchasing this volume is $8 per month, not $6 per month (paying a higher unit cost for the low-carbon energy purchases).
c) If confirmed, is there a unit cost threshold ($\$/m^3$ or potentially $\$/CO2_e$) at which Enbridge Gas would elect to cease further purchase of low-carbon energy supply?

4.2-Staff-34

Ref: Exhibit 4, Tab 2, Schedule 7, Attachment 1

Enbridge Gas provided letters of support for the LVCP.

a) With all the letters of support provided, why does Enbridge Gas need to consider costs going to the general pool? The Federation of Rental-housing Providers of Ontario would represent nearly 10% of Enbridge Gas customers and a signed commitment to the program should allow Enbridge Gas to achieve its 1-4%

targets without requiring the pool of Ontario rate payers to see any increased costs, both for RNG and for marketing.

4.2-Staff-35

Ref: Exhibit 4, Tab 2, Schedule 7, p. 10, 17-18 and Attachment 2, p.16

Enbridge Gas notes that it is aware of multiple large volume sales service customers who have expressed interest in Renewable Natural Gas (RNG) in their gas supply. Enbridge Gas describes the Voluntary RNG Pilot Program and notes the lower than expected participation by customers. The Avista report (p. 16) notes that “many of the companies that have voluntary RNG programs have much smaller residential and/or commercial gas volumes than Enbridge Gas …and the ability to secure larger percentages of their total natural gas demand is simplified due to these smaller required volumes”.

a) Given the lower than expected participation by customers in the Voluntary RNG Pilot Program, what indication does Enbridge Gas have that the interest of large volume customers in RNG will translate into LCVP purchases?
b) The finding in the Avista report (p. 16) suggests that the scale of Enbridge Gas’s LCVP program could pose a risk in both securing a sufficient level of voluntary participation, and in procuring the target volume of low-carbon energy. Would Enbridge Gas agree, and if so, how does it plan to address these risks?
c) Does Enbridge Gas propose a target or performance metric for the percentage of low-carbon energy purchased by Enbridge Gas that would be purchased voluntarily through the LCVP by large volume sales service customers? Why or why not?

4.2-Staff-36

Ref: Exhibit 4, Tab 2, Schedule 7, pp. 15-16, 26-27

Enbridge Gas notes that its proposal to procure low-carbon energy is a cost-effective means to reduce emissions, and can contribute to meeting both Ontario’s and Canada’s greenhouse gas emissions targets. Enbridge Gas estimates that its low-carbon energy proposal would reduce emissions by over 1.06 Mt of CO_2 by 2029. Enbridge Gas notes that FortisBC imports 18% of its RNG supply from Ontario, and that Enbridge Gas also has the ability to purchase RNG produced outside of Ontario.

a) Please provide the supporting calculation for the estimated 1.06 Mt emissions reduction.
b) Please confirm that this calculation assumes that RNG is completely free of CO_2e emissions and does not consider additionality of emissions reductions or life-

cycle emissions (including avoided methane emissions). If not confirmed, please provide Enbridge Gas's assumptions.

c) Please estimate the unit cost of CO_2e emissions reductions through the LCVP program, stating any assumptions necessary for this calculation.
d) Please confirm that interprovincial transfers of RNG ownership (e.g., whether Fortis BC or Enbridge Gas had ownership rights to a given source of RNG supply) would not have an impact on Canada's overall calculated greenhouse gas emissions and progress towards its emissions targets but would impact Ontario's calculated emissions and progress toward its emissions targets. If not confirmed, please provide additional details.

4.2-Staff-37

Ref: Exhibit 4, Tab 2, Schedule 7, pp. 30-32

Enbridge Gas discusses the lifecycle carbon intensity approach of estimating greenhouse gas emissions associated with RNG, and notes that the carbon intensity score of RNG will not be the primary consideration when procuring RNG. Enbridge Gas notes that it has not determined at this time if RNG will be purchased with or without Clean Fuel Registry (CFR) credits.

a) Does the potential separation of CFR credits (the potential for an RNG supplier or Enbridge Gas to sell CFR credits to another purchaser, separate from the RNG) introduce a risk that emissions reductions from an RNG supply source will be double-counted (once by the purchaser of the CFR credits, once by a customer purchasing RNG through the LCVP), and thus deliver limited additional emissions reductions? Please describe as needed.
b) Enbridge Gas's LCVP proposal makes no mention of additionality – i.e., whether the low-carbon energy purchased by Enbridge Gas is providing incremental economy-wide greenhouse gas emissions reductions relative to what would occur in the absence of the LCVP program (e.g., by leading to development of new supply sources as opposed to re-routing RNG that, in the absence of the LCVP program, may have been otherwise used to reduce emissions outside of Enbridge Gas's distribution volumes). Does Enbridge Gas plan to assess and report on additionality considerations associated with the LCVP? Why or why not?
c) What information does Enbridge Gas intend to provide to potential voluntary participants in the LCVP, to make them aware of Enbridge Gas's approach to additionality, life-cycle intensity, and CFR credits in its low-carbon energy purchases, in order to enable customers to determine if low-carbon energy purchased through the LCVP is compatible with customers' greenhouse gas emissions reductions or net zero goals?

8.1-Staff-38

Ref: Exhibit 8, Tab 1, Schedule 2, pp. 2-3 and Attachment 1

Enbridge Gas proposes allocation of the ETTF cost using a customer charge that is identical for customers in all rate classes, therefore the cost of the ETTF is recovered primarily from general service customers (Attachment 1).

Did Enbridge Gas consider alternative approaches to rate class allocation that might better align with the customer share of benefits likely to be achieved through the ETTF? Please describe why Enbridge Gas believes that a common customer charge is the preferred approach.

9.1-Staff-39

Ref: Exhibit 9, Tab 1, Schedule 3, pp. 3-4

Enbridge Gas proposes a total of $20 million in ETTF spending, the funding of which will be collected over the IR term and tracked in the variance account. Enbridge Gas also proposes that the ETTF rate rider would be effective with the first QRAM following the Phase 2 Decision, and notes that, for 2025, the forecast amount to be collected could be less than $5 million due to the timing of the Phase 2 Decision.

a) Does Enbridge Gas propose that the amount collected through the rate rider over the IR term would serve as a cap on ETTF spending, i.e., Enbridge Gas would have an obligation to ensure that the balance brought forward for disposition at the end of the IR term is not a debit to be recovered from ratepayers?
b) If so, how would this be affected should the amount collected in 2025 be less than $5 million (i.e., would Enbridge Gas's spending cap over the IR term remain at $20 million, or would it be reduced commensurate with the reduced amount recovered through rates)?
c) If not, what mechanisms does Enbridge Gas propose be put in place to ensure that any additional funding beyond the budgeted amount is appropriate?

9.1-Staff-40

Ref: Exhibit 9, Tab 1, Schedule 3, p. 13; Phase 1, Exhibit 4, Tab 4, Schedule 3, p.5, 6

Enbridge Gas describes anticipated work resulting from OEB directives or requirements in phase 1 of the OEB decision (including stranded asset risk assessment), and provides preliminary cost estimates for this work, that Enbridge Gas proposes be recorded in a new OEB Directive Deferral Account.

OEB staff notes that Enbridge Gas's phase 1 evidence proposed FTE additions in the Business Development & Regulatory department, including the Energy Transition

Planning Group (including FTE additions dedicated to integrated resource planning), and in the Distribution Operations department.

a) Please describe why some or all of the listed activities related to stranded asset risk assessment are not within the scope of work of Enbridge Gas's normal business activities over the rebasing term (in particular, the Business Development & Regulatory department, including the Energy Transition Planning Group; and/or the Distribution Operations department), and cannot be conducted within Enbridge Gas's approved O&M budget.
b) Could some or all of the listed activities related to stranded asset risk assessment be recorded within either Enbridge Gas's existing IRP Operating Costs Deferral Account (179-318), or Enbridge Gas's Distribution Integrity Management Program Variance Account (179-326) approved in Phase 1 of the proceeding? Please describe why Enbridge Gas believes the use of the OEB Directive Deferral Account is preferable.

9.1-Staff-41

Ref: Exhibit 9, Tab 1, Schedule 3, pp. 11-15 and Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p.38.

In its evidence, Enbridge Gas has proposed to establish an OEB Directive Deferral Account to record the incremental costs incurred by Enbridge Gas to respond to OEB directives and requirements from this proceeding. In Table 1 of Reference 1, Enbridge has outlined a list of the work required to be completed to address the directives in the Phase 1 Decision and preliminary cost estimates.

Reference 2 states that "the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for customers."

a) Please provide any precedents where the OEB has approved a similar deferral account.
b) Please provide evidence to demonstrate that all the anticipated work listed in Table 1 of Reference 1 represents a cost-effective option for customers as directed in Reference 2.

10-Staff-42

Ref: EB-2024-0078, Notice of Motion, January 29, 2024
EB-2024-0078, Fresh as Amended Motion for Review and Variance, Updated May 29, 2024, pp. 11 & 12
EB-2024-0063, OEB Letter, April 22, 2024

In its Notion of Motion, Enbridge Gas requested that the OEB review and vary its decision to set the deemed equity component of its cost of capital at 38%, rather than the requested 42%. After the Notice of Motion was filed, the OEB initiated a new generic cost of capital proceeding (EB-2024-0063).

In the Amended Motion, Enbridge Gas stated that it would be duplicative and inefficient to pursue its review of the OEB's deemed capital structure decision at the same time as the OEB is also considering that item in a separate and concurrent proceeding.

Enbridge Gas further stated that it will advance its position about the proper deemed capital structure in the new generic proceeding and may assert that any determinations in that case be applied to Enbridge Gas's rates and revenue requirement during the current IRM ratemaking term.

On April 22, 2024, the OEB approved the final Issues List for the generic cost of capital proceeding, including the following two issues, amongst other issues:

18. How should any changes in the cost of capital parameters and/or capital structure of a utility be implemented (e.g., on a one-time basis upon rebasing or gradually over a rate term)?
19. Should changes in the cost of capital parameters and/or capital structure arising out of this proceeding (if any) be implemented for utilities that are in the middle of an approved rate term, and if so, how?

Please confirm that the applicant proposes to implement the outcomes from the OEB's generic cost of capital proceeding, including what the OEB decides with respect to implementation. If this is not the case, please explain.

10.1-Staff-43

Ref: Exhibit 10, Tab 1, Schedule 1, pp. 5-8

In Phase 1, the OEB directed Enbridge Gas to file a proposal to reduce the capitalized indirect overhead balance by $50 million in each year of the IR term and expense it as O&M, as part of the IRM issue in Phase 2.

Enbridge Gas is proposing the inclusion of an annual base rate adjustment with respect to the change in treatment of indirect overhead capitalization as directed by the OEB in Phase 1.

Enbridge Gas is proposing an annual base rate adjustment of $56.9 million in 2025, $52.0 million in 2026, $47.1 million in 2027 and $40.7 million in 2028.

a) Did Enbridge Gas consider any other mechanisms to reduce the capitalized indirect overhead balance by $50 million in each IR year as directed by the OEB in Phase 1? Please discuss in detail other options considered by Enbridge Gas and why these options were rejected.

b) Please provide the total annual base rate adjustment related- bill impacts for a typical residential customer in each Enbridge Gas rate zone, for each IR year.

10-Staff-44

Ref: Exhibit 10, Tab 1, Schedule 1, Pages 9-11
Exhibit 10, Tab 1, Schedule 1, Attachment 1, Page 8, Black & Veatch Study

Black & Veatch stated that Enbridge Gas's current IRM uses an economy-wide inflation factor (i.e., the GDP IPI-FDD). However, in the current proceeding, Enbridge Gas has proposed an inflation factor that is calculated as a weighted average of inflation in a labour sub-index and a non-labour sub-index.

Enbridge Gas proposes that the inflation factor be calculated as the weighted sum of:

- 75% for the non-labour component (calculated as the calendar year-over year percentage change in the annual average of Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand (GDP IPI FDD) available for the most recent calendar year),[2] and
- 25% for the labour component (calculated as the calendar year-over-year percentage change in the annual average of Ontario fixed weighted index of Average Hourly Earnings (AHE) available for the most recent calendar year)[3]

OEB staff has prepared the following table that summarizes the inflation methodology used for the different Ontario sectors. The calculation of the inflation factor for each sector (electricity distribution and electricity transmission) uses the same data from Statistics Canada and the same basic formula, but differs for each sector based on the weights.[4]

[2] Statistics Canada. (2024 Feb 29). Canada- Price indexes, gross domestic product; Canada; Implicit price indexes; Final domestic demand; 2007=100, Table: 36-10-0106-01 (formerly CANSIM 380-0066), v62307283. https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=3610010601
[3] Statistics Canada. (2024 Mar 28). Fixed weighted index of average hourly earnings for all employees (SEPH), excluding overtime, unadjusted for seasonal variation, for selected industries classified using the North American Industry Classification System (NAICS); Ontario; Industrial aggregate excluding unclassified businesses; Index, 2002=100, Table: 14-10-0213-01 (formerly CANSIM 281-0039), v1606242. https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1410021301
[4] OEB Letter, 2024 Inflation Parameters, June 29, 2023

Table 1: Summary of Inflation Methodology for Different Ontario Sectors

Sector	**Component Weighting**	
	Non-Labour – GDP-IPI(FDD)	Labour - AWE
Electricity Distribution	70%	30%
Electricity Transmission	86%	14%
	Component Weighting	
	Non-Labour – GDP-IPI(FDD)	Labour - AHE
Enbridge Gas (Proposed)	75%	25%
Enbridge Gas (Current)	100%	0%

The OEB uses a non-labour measure of GDP-IPI (Gross Domestic Product – Implicit Price Index – Final Domestic Demand – Canada).

The OEB uses a labour measure of AWE (Average Weekly Earnings – Including Overtime – Industrial Aggregate excluding Unclassified Businesses – Ontario).

EPCOR Natural Gas Limited Partnership uses the electricity distribution inflation factor for its annual rate adjustments for its two natural gas service territories (as noted in EB-2018-0264 and EB-2018-0336).

a) Please confirm that Enbridge Gas proposes to use the same inflation factor methodology as that currently used by the OEB for electricity distributors and electricity transmitters as shown in Table 1, except for the following:
   i. Different weightings between the non-labour and labour proportions
   ii. Its proposal to use an AHE measure rather than an AWE measure
b) If this is not the case, please explain.
c) Please provide Enbridge Gas's, and, if necessary, Black and Veatch's, views on the rationale for Enbridge Gas's proposed inflation factor in light of the existing alternatives.

d) Are there any other measures of inflation that Enbridge Gas and/or Black and Veatch considered as alternatives? If so, please identify and explain.

10-Staff-45

Ref: Exhibit 10, Tab 1, Schedule 1, Pages 9-11
Updated: 2024-03-15 EB-2022-0200 Rate Order Working Papers Schedule 11
EB-2017-0306/EB-2017-0307 Union Gas Limited and Enbridge Gas Distribution Inc., Decision and Order, August 30, 2018, Amended on September 17, 2018, p. 37

As also noted above, in the current proceeding, Enbridge Gas has proposed an inflation factor that is calculated as a weighted average of inflation in a labour sub-index and a non-labour sub-index.

OEB staff notes that the impact of Enbridge Gas's proposal to use the Ontario AHE inflation index, as opposed to the Ontario AWE inflation index, as well as changing the weights between non-labour and labour, likely has an immaterial impact on Enbridge Gas's revenue requirement. OEB staff's opinion is derived on the basis that Enbridge Gas potentially adopts the OEB's methodology used for electricity distributors, instead of its proposed approach set out in this application.

a) Please provide a calculation of the 2025 Inflation Parameters percentage using the OEB's methodology for electricity distributors.
b) Please provide a calculation of the 2025 Inflation Parameters percentage using Enbridge Gas's proposed approach, as set out in this application.
c) Please calculate the difference between the percentages calculated in parts a) and b) of this interrogatory.
d) Please apply the difference in part c) of this interrogatory to Enbridge Gas's 2024 base revenue requirement of $6,061.4 million.
e) Please compare the number calculated in part d) of this interrogatory to Enbridge Gas's materiality threshold of $5.5 million.
f) Please elaborate whether Enbridge Gas agrees or disagrees with OEB staff's statement that the impact of Enbridge Gas's proposal to use the Ontario AHE inflation index, as opposed to the Ontario AWE inflation index, as well as changing the weights between non-labour and labour, has an immaterial impact on Enbridge Gas's revenue requirement. Please also address the difference noted in part e) of this interrogatory, as well as in the context of Enbridge Gas potentially adopting the OEB's methodology used for electricity distributors, instead of its proposed approach set out in this application.

g) Please confirm that Enbridge Gas proposes to use the following downloads from Statistics Canada, subject to changes in the release date. If this is not the case, please provide the correct downloads from Statistics Canada that Enbridge Gas proposes to use.

AHE

Fixed weighted index of average hourly earnings for all employees, by industry, monthly 1 2 3 4 5						
Frequency: Monthly						
Table: 14-10-0213-01 (formerly CANSIM 281-0039)						
Release date: 2024-05-30						
Geography: Canada, Province or territory						
Geography	Ontario					
North American Industry Classification System (NAICS) 4	Industrial aggregate excluding unclassified businesses 6 7					
Reference period						
	Index, 2002=100					

GDP-IPI (FDD)

Gross domestic product price indexes, quarterly	
Frequency: Quarterly	
Table: 36-10-0106-01 (formerly CANSIM 380-0066)	
Release date: 2024-05-31	
Geography: Canada	
Geography	Canada
Index	Implicit price indexes
Estimates	Final domestic demand
Reference period	
	2017=100

10-Staff-46

Ref: Exhibit 10, Tab 1, Schedule 1, Page 11
Exhibit 10, Tab 1, Schedule 1, Attachment 1, Page 24, Black & Veatch Study

Enbridge Gas stated that it has proposed a 25% weighting for labour and 75% weighting for non-labour because these weights are broadly consistent with the share of non-labour and labour costs for Enbridge Gas and other gas distributors.

In its study, Black and Veatch noted that its proposed 25% and 75% weights are generally consistent with the shares of labour and non-labour costs for both Enbridge Gas and U.S. distributors.

Black and Veatch also noted that a 25% share is more strongly supported by its empirical work and estimated labour cost shares for both Enbridge Gas and the U.S. gas distribution industry.

a) At a high level, please provide an analysis that supports Enbridge Gas's statement that it has proposed a 25% weighting for labour and 75% weighting for non-labour because these weights are broadly consistent with the share of non-labour and labour costs for Enbridge Gas and other gas distributors.
b) At a high level, please explain why a 25% labour share is more strongly supported by Black and Veatch's empirical work and estimated labour cost shares for both Enbridge Gas and the U.S. gas distribution industry.

10.1-Staff-47

Ref: Exhibit 10, Tab 1, Schedule 1, pp. 21-22

Enbridge Gas is proposing to combine the "advanced" element of the Advanced Capital Module (ACM) with the Incremental Capital Module (ICM) by seeking to file the ICM funding request with the leave to construct application for the relevant project.

Enbridge Gas states that the ICM and ACM in their current form do not work for the company and that its proposal will address concerns with certainty of cost recovery of capital investments.

a) Please discuss Enbridge Gas's view as to whether this proposed modified approach to ICM funding is consistent with current OEB policy.
b) Please explain how Enbridge Gas will determine that a project, subject to leave to construct approval, will qualify for and could require incremental funding prior to the determination of the maximum eligible incremental capital for the applicable rate year. Please specify the criteria Enbridge Gas will apply to determine if it will seek ICM funding for a project with the leave to construct application.
c) Please provide a list of projects that Enbridge Gas anticipates seeking advanced ICM funding with the leave to construct application during the IR term.
d) Referencing other OEB regulated utilities, please provide all examples known to Enbridge Gas where a similar advanced ICM funding request structure is utilized. Please explain how Enbridge Gas's proposal is similar and different from these examples.

10.1-Staff-48

Ref: Exhibit 10, Tab 1, Schedule 1, pp. 22-23

Enbridge Gas is proposing that an additional off-ramp be included, where a regulatory review could be requested before utility earnings deviations of +/- 300 basis points are realized where a change in legislation or policy impacts Enbridge Gas's operating environment, that is not readily able to be addressed through the Z factor.

Enbridge Gas stated it should not have to wait for a material change in utility earnings to materialize before rates can be adjusted to reflect the new operating parameters.

a) Please explain why Enbridge Gas did not include this additional off-ramp proposal with its original incentive rate-making proposal in Phase 1.
b) Please provide an example of a legislation or policy impact where Enbridge Gas would request an off-ramp.
c) Referencing other OEB regulated utilities, please provide all examples known to Enbridge Gas where a similar additional off-ramp mechanism is utilized. Please explain how Enbridge Gas's proposal is similar and different from these examples.
d) Please describe how the proposed additional off-ramp is different from the Z factor parameter in Enbridge Gas's proposed Price Cap IR plan. Please list the circumstances where Enbridge Gas would utilize the additional off-ramp vs. the Z factor mechanism.
e) Please provide a rationale as to why the proposed change to the off-ramp is necessary in Enbridge Gas's proposed Price Cap IR plan.
f) Please provide details regarding the timing in which Enbridge Gas would file any additional off-ramp (i.e., with the annual rate application, as a stand-alone application, etc.).

10.1-Staff-49

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, Black & Veatch Study

Enbridge Gas retained Black and Veatch to undertake Total Factor Productivity and benchmarking research for an overall X factor recommendation and an inflation factor recommendation to support Enbridge Gas's IRM proposal. The Black and Veatch study is provided at the above reference.

a) What is the definition used by US distributors for transmission pipe? What is Enbridge Gas's definition for transmission pipe?
b) For each of the 54 US distributors used in the BV report, please provide the absolute length and % of length of their mains which are >30% SMYS.

c) For the last 10 years, please provide the costs incurred by Enbridge Gas to replace cast iron.
d) Have any projects to replace bare and unprotected steel mains been deferred or delayed (not due material procurement, weather, or COVID) over the last ten years? If yes, how many kilometres of replacement have been deferred or delayed?
e) Does Enbridge Gas believe that the technical regulations in place through CSA is similar to what is experienced through PHMSA?
f) Does Enbridge Gas believe that the technical regulations in place through CSA is as prescriptive as PHMSA?
g) Are there any significant differences between PHMSA and CSA regulation in regard to the installation, maintenance, inspection and repair of:
    i. Steel pipe
        i. Transmission = >30% SMYS
        ii. Distribution = <30% SMYS
    ii. Cast iron pipes
    iii. Plastic pipes

10.1-Staff-50

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, Page 1, Black & Veatch Study

In the study, Black & Veatch noted that Enbridge Gas's inflation proposal is an example of an "industry-specific" inflation factor, which is designed to track industry input price trends more closely than economy-wide price inflation.

Please explain how Enbridge Gas's proposal "track[s] industry input price trends more closely than economy-wide price inflation", as opposed to the OEB's current inflation methodology in place for electricity distributors.

10.1-Staff-51

Ref: Ontario Energy Board Filing Requirements for Natural Gas Rate Applications, pp. 7-8 and EB-2022-0200, Exhibit 2, Tab 4, Schedule 1, p. 2

On pages 7-8 of the Filing Requirement, the OEB stated that:
Most utilities regulated by the OEB were required to adopt International Financial Reporting Standards for financial reporting by January 1, 2015. In the Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment, the OEB indicated that it would require utilities to explain the use of an accounting standard other than modified International Financial

Reporting Standards (MIFRS). On this basis, the following accounting standards may be applicable to natural gas utilities for 2015 and beyond:

- International Financial Reporting Standards (IFRS)
- United States Generally Accepted Accounting Principles (USGAAP)
- Accounting Standards for Private Enterprise (ASPE)

Applications filed using Canadian Generally Accepted Accounting Principles (CGAAP) will no longer be accepted.

On page 2 of Exhibit 2, Tab 4, Schedule 1 Enbridge stated that
EGD and Union operated under their respective capitalization policies from 2013 through to the merger of Enbridge Inc. and Spectra Energy Corp. There were no significant changes to either of the capitalization policies from 2013 to the middle of 2018.

a) Did EGD or Union Gas change their accounting standards during the 2006-2018 period? If so, when was that change made, please discuss the salient changes, and how did it affect reporting of costs and plant?
b) Did the merger of EGD and Union Gas result in either company changing accounting standards? If so, when was that change made, what was the change, and how did it affect reporting of costs and plant?
c) What were the capitalization policies of EGD and Union Gas prior to 2013? How did they change?

10.1-Staff-52

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1

PEG is interested in better understanding company-specific factors it should consider in any benchmarking work.

Please discuss any Enbridge Gas-specific business operating conditions relative to the US gas distribution industry that may have an impact on benchmarking, both favorable and unfavorable to Enbridge Gas. If there is underlying data to measure these concerns, please provide them.

10.1-Staff-53

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 3

BV states that

> EGI retained Black & Veatch Management Consulting (BV) to undertake Total Factor Productivity (TFP) and benchmarking research to support the Company's

IRM proposal. Dr. Lawrence Kaufmann oversaw and managed this work on behalf of BV.

a) Please identify all publicly available US gas utility productivity studies that Dr. Kaufmann has previously undertaken.
b) Please identify all publicly available statistical benchmarking studies of gas utility cost that Dr. Kaufmann has previously undertaken.

10.1-Staff-54

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 4

BV states that

> Our study estimates a long-run TFP trend for U.S. gas distributors of -1.52 % per annum. This value is in line with productivity offsets proposed by, and approved for, U.S. gas distributors in recent regulatory proceedings.

a) Please identify any decisions in which a regulator acknowledged a negative productivity growth target for a gas utility.
b) Please confirm that the Alberta Utilities Commission has declined to approve a negative productivity growth target for jurisdictional gas utilities on three occasions.

10.1-Staff-55

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 10

BV states that

> the trend in industry unit cost is decomposed into two factors: the GDPPI as the inflation factor, and the term in brackets as the X factor. However, this X factor is not equal to the industry TFP trend, as it is when an industry-specific inflation factor is used to measure industry input price trends. Instead, the X factor is now equal to the sum of two other terms: 1) a productivity differential, equal to the difference between the TFP trends of the industry and the overall economy, and 2) an inflation differential, equal to the difference between the input price trends of the economy and the industry.
>
> It should be noted that this X factor is not simply a theoretical implication of the indexing logic when economy-wide inflation factors are used in IRMs. This more complex X factor formula has in fact been implemented in many Performance-Based Regulation ("PBR") plans. For example, the Massachusetts Department of

> Public Utilities has used the sum of the productivity differential and inflation differential to calculate X factors in at least eight approved indexing plans. This same formula has also been applied in New Zealand and Australia and was recently proposed for a PBR plan in Hawaii.

Please confirm the following statements.

a) Enbridge Gas's proposed inflation factor formula includes an Ontario labor price index as well as a macroeconomic inflation measure.

b) The multifactor productivity trend of Canada's economy is zero or negative.

c) Hawaii's regulatory commission chose not to correct its revenue cap index for the use of GDPPI as the inflation measure and chose an X factor (exclusive of stretch) of zero.

10.1-Staff-56

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, pp. 12, 20, and 36

On three occasions in its report, a BV team is directly referenced.

In footnote 8 on page 12, BV states that

> The BV team used independently-reported data from Colonial Gas as much as possible, but combined Colonial Gas with Boston Gas in 2021 and 2022 to compute cost and input data.

On page 20, BV states that

> Dr. Kaufmann of the BV team agrees with the OEB's position that stretch factors can be appropriate in updated IRMs.

On page 36 BV states that

> Dr. Kaufmann of the BV team consulted directly with U.S. Bureau of Labor Statistics (BLS) personnel to ensure that the capital input price in this study was as consistent as possible with the BLS formula.

a) Please identify the other members of the BV team and their roles in developing this report.

b) Please provide all publicly available utility productivity and benchmarking research undertaken by BV team members other than Dr. Kaufmann.

10.1-Staff-57

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 12

BV states that

> There were sufficient data from S&P to estimate TFP trends for 54 U.S. gas distributors. This sample includes a diverse array of small, medium and large gas distributors throughout all regions of the country.

a) Why include data for small distributors like St. Joe Gas (2,878 customers in 2022) in the sample? Were the small distributors included in the transnational unit cost comparisons?
b) Please explain the rationale for excluding the following companies from the BV sample: Columbia Gas of Pennsylvania, Hope Gas, Indiana Gas, Northwest Natural Gas, NSTAR Gas, Ohio Valley Gas, PECO, Public Service of Colorado, and Dominion Energy South Carolina (f/k/a South Carolina Electric & Gas).
c) Please explain how the Boston Gas - Colonial merger was handled in the productivity calculations. Does the count of 54 distributors apply prior to the merger and 53 after the merger?
d) Was the Boston Gas – Colonial Gas merger the only one amongst BV's sample during its sample period? Why weren't other utilities (e.g., Ameren Illinois, NSTAR Gas) that experienced a merger during the sample period included in the sample?
e) What criteria did BV use to include or exclude gas distributors from its US sample?

10.1-Staff-58

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 12 and p. 37

BV states that

> EGI's distribution cost measure was computed to facilitate "apples to apples" comparisons between EGI and U.S. gas distributors. Most sampled U.S. distributors had negligible (or zero) transmission and storage assets, so BV computed total costs for the gas distribution operations only of sampled distributors. It was therefore necessary to compute measures of EGI's distribution-only costs to enable appropriate benchmarking comparisons between EGI and the U.S. gas distribution industry.

On page 37 BV provides its definition of O&M expenses included in the study. This definition of O&M expenses of gas distributors includes underground and other storage expenses.

Please clarify where storage is included vs. where it is excluded from the O&M, capital, and total cost calculations.

10.1-Staff-59

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 13 and Attachment 2

BV states that

> Inputs were categorized into three categories: labour, capital, and non-labour O&M inputs. Labour quantity was equal to annual labor costs divided by an employment cost index… The quantity of non-labour O&M for U.S. distributors was computed by dividing total O&M costs, net of labour costs, by the U.S. GDPPI.

a) How did BV decompose the reported O&M expenses of US gas utilities into labor and non-labor costs? The working papers provided only contain values for labor cost. Please provide the source of these values and any associated calculations and data if these values are calculated. S&P does not appear to have salaries and wages data for many of the gas distributors in the BV sample. An examination of the working papers suggests that the split between labor and non-labor O&M expenses for US companies seems to have been calculated by multiplying O&M by a value that is the same for all US companies for a given year. If true, please provide the basis for this allocator.

b) Does the definition of labor cost used in the study include pensions and other benefits or is this treated as non-labor?

c) Since labor and non-labor O&M expenses were imputed, why calculate and report the trends of labor and non-labor O&M inputs rather than the trend of O&M inputs?

d) Please calculate the year-to-year labor, non-labor O&M, O&M, and capital productivity growth of Enbridge Gas and the sampled US utilities.

10.1-Staff-60

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 14 and pp. 18-19

BV states that

> Negative TFP growth for the U.S. gas distribution industry is therefore the result of slowing output growth coupled with simultaneously rapid capital spending. These empirical results are consistent with generally recognized trends in the industry, including slow output growth and the need to replace aged gas distribution infrastructure for safety, reliability and policy-related reasons. All of these trends are particularly pronounced in the Northeast U.S.

and that

The Company's cost performance is even better when compared against the Northeast industry, which is a more relevant comparator for EGI than the national industry for at least three reasons. One is that gas distributors in the Northeast have a much larger share of cast iron and bare steel assets within their territory. This, in turn, results from the fact that gas distribution systems in the Northeast U.S. were developed earlier than in most of the U.S., simply because this region was settled earlier and therefore has more long-settled, "mature" large cities where the industry's initial infrastructure was installed… EGI has now replaced nearly all its aged cast iron or bare steel assets...

EGI also faces weather and geography issues that are similar to those in the Northeastern U.S. and which tend to increase costs. The cost of installing and maintaining distribution assets is generally greater where frost depths are deeper and ground conditions are more rocky. Both of these factors are more prevalent in Ontario and the Northeast U.S. than in much of the rest of the U.S.….

BV believes the best inference on EGI's cost performance can be obtained by comparing the Company to the Northeast U.S. gas distribution industry and to the average performance of its seven selected peers.

a) Why does an outsized reliance on cast iron and bare steel mains make Northeast gas utilities more relevant to Enbridge Gas when it has now replaced nearly all its aged cast iron or bare steel assets? Did northeast gas distributors not have a more pressing need to replace aging assets over BV's 2007-2022 sample period than Enbridge Gas had during this period and that Enbridge Gas will have in the next five years?
b) Please provide substantiation that frost depth matters. Even if it does, why does that not make distributors in the great lakes states suitable peers?
c) Please confirm that the best peer group to benchmark the cost level of Enbridge Gas might differ from the best peer group to establish a productivity growth target.
d) How does the recent historical customer growth trends of sampled Northeast distributors compare to that which Enbridge Gas expects in the next five years?
e) Please forecast the growth in Enbridge Gas's customers, kilometers of distribution and transmission, and storage capacity in the next five years.

10.1-Staff-61

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 15

BV states that:

> Importantly, EGI and the industry as a whole exhibit similar capital input trends. For the last 16 years, capital input has grown by more than 3% per annum for EGI's total operations, EGI's distribution operations, and the overall industry. This is evidence of long-standing capital spending pressures throughout the industry. EGI's capital input growth (3.34% for all operations and 3.22% for distribution operations) has closely tracked the industry's overall trend of 3.25% per annum.

Please confirm the following.

a) Enbridge Gas's capital quantity trend has been bolstered by comparatively rapid customer growth. However, Enbridge Gas claims that this will slow prospectively.

b) Enbridge Gas's capital quantity growth was influenced by the strength of capex containment incentives under its successive multiyear rate plans.

10.1-Staff-62

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 16

BV states that

> Data used in the TFP study was also used to benchmark EGI against the U.S. gas distribution industry. This benchmarking study examines EGI's unit cost (UC) of production for gas distribution against the U.S. industry. Unit cost is equal to the total cost of production divided by output, as measured by customer numbers. Unit costs are therefore equal to total gas distribution costs per customer.

a) Please confirm that BV's unit cost benchmarking method did not consider differences in the input prices faced by sampled US utilities.

b) Why were unit cost metrics used in the benchmarking instead of productivity metrics that controlled for differences between the input prices faced by sampled utilities as well as differences in their operating scale?

c) Why was econometric benchmarking not used in this study when this approach was favored in the RRFE proceeding in which Dr. Kaufmann participated?

d) Please confirm that econometric benchmarking would automatically control for differences between sampled utilities in operating scale, input prices, and several additional business conditions.

e) Please identify all prior cases in which Enbridge Gas or a predecessor gas distributor in Ontario submitted an econometric benchmarking study.

f) Please identify all instances in which Kaufmann Consulting has prepared a publicly-available econometric benchmarking study.

g) Why did BV not provide itemized benchmarking results for O&M and capital costs using U.S. data?

h) Did Enbridge Gas additionally commission BV to undertake econometric cost benchmarking or unit cost benchmarking of O&M, capital, or capex cost? If so, please provide those results.

i) Please provide the request for services and the statement of work for the project.

10.1-Staff-63

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 16

BV states that

> Utility benchmarking studies often compare a company to selected "peer" utilities that operate under similar business conditions. Two salient business conditions should be considered when identifying peers for EGI. The first is that EGI is one of the largest gas distributors in North America, serving approximately 3.8 million distribution customers. Larger utilities often benefit from economies of scale that reduce the unit cost of operations. In addition, the EGD and Union South rate zones serve relatively dense service territories, which include the central business district and metropolitan area of one of North America's largest cities (Toronto).

a) Please provide substantiation from publicly-available econometric studies of gas distributor cost that these are the two most important two business conditions to consider in choosing a unit cost peer group for Enbridge Gas.

b) Does the use of unit cost metrics not reduce the need to include large utilities in the peer group?

c) Why not compare Enbridge Gas to distributors that, like Enbridge Gas, serve an "all of the above" mix of urban cores, suburbs, and smaller cities and towns?

d) What are the five U.S. gas distributors that, in BV's view, individually face business conditions that are most similar to those of Enbridge Gas on balance?

10.1-Staff-64

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, pages 17-18 and Attachment 2

In Table 5, BV presents its unit cost benchmarking comparisons for the 2020-2022 period. The values for the U.S. Sample and Northeast U.S. do not line up with values reported in its working papers, specifically Attachment 2, Calculation tab cells AN25-AN27 for the US and cells AO25-AO27 for the Northeast U.S. In addition, the average unit cost value for Public Service Electric & Gas reported in Table 5 appears to be a

2019-2021 average (e.g., there is no calculated 2022 unit cost for this company as seen in cell AP952 of the Attachment 2's Calculation tab).

a) Which unit cost values for the U.S. Sample and Northeast U.S. are correct?
b) Please confirm that the unit cost value for Public Service Electric & Gas as reported in Table 5 is incorrect.
c) Please provide a revised Table 5 with the updates or corrections.

10.1-Staff-65

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 18

BV states that "EGI has now replaced nearly all its aged cast iron or bare steel assets". PEG wishes to use data from the Pipeline Hazardous Materials Safety Administration on the length, age, and construction material of US natural gas mains for cost benchmarking and productivity trend measurement.

Please provide data for as many years as possible from 2006 to 2022 on the percentages of Enbridge Gas's mains that are made of cast iron or unprotected bare steel (separately for EGD and Union Gas from 2006 to 2018).

10.1-Staff-66

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 19

BV states that

> Unlike U.S. gas distributors, Canadian gas distributors are not required to report output, cost, and related data on standardized forms to federal government authorities. Accordingly, Canadian gas distribution data must be collected from a number of disparate sources.

Please confirm that most US gas distributors do not routinely provide comprehensive and itemized cost data to the federal government.

10.1-Staff-67

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 26-29

BV states that

> In addition to Ontario and Massachusetts, Alberta has become the third leading PBR/IRM jurisdiction in North America. In October 2023, the Alberta Utilities Commission approved its third, five-year PBR plan. Both the second ("PBR2") and third ("PBR3") PBR plans approved in Alberta included I-X indexing formulas similar to those used in Ontario and Massachusetts.

However, PBR2 and PBR3 also include a significant expansion of the I-X framework used to update utilities' allowed revenues. In addition to this formula, PBR2 and PBR3 also include a "kbar" mechanism, which provides another, independent source of revenues for utilities. As a result, the Alberta PBR plans are not simply I-X mechanisms; they are more accurately described as I-X+K plans….

The K-bar is therefore a source of supplemental revenues, in addition to revenues provided under the I-X formula, to fund and manage *business as usual activities* (emphasis added). The k-bar is not used to fund energy transition and related policy initiatives; those costs are recovered through the Type 1 capital tracker mechanism mentioned above.

Although the k-bar is different in some respects from the I-X mechanism, there are also important similarities. First, both are formula-based mechanisms. Relatedly, they both create strong performance incentives. They are also designed to support utilities' ongoing "basic business" rather than address one-time or extraordinary costs….

Alberta's approved X and K factors are clearly congruent with Massachusetts' approved negative X factors, as well as BV's recommended negative X factor for EGI…The transformation from I-X to I-X+K in Alberta becomes functionally equivalent to a negative X factor whenever the value of the kbar exceeds the value of (-X).

a) Please confirm the following statements.
    1. Under PBR2 and PBR3, Alberta's gas and electric power distributors are compelled to live with the supplemental funding that K-Bar provides for most kinds of capex. The role of forecasting in the determination of capital revenue has thereby been greatly reduced.
    2. The Alberta Utilities Commission did not approve any requests for Type 1 capital revenue supplements during PBR2.
    3. In PBR3, the Alberta Utilities Commission broadened the eligibility requirements for Type 1 capital to include energy transition projects that were "directly caused by applicable law related to net-zero objectives."
    4. Enbridge Gas's proposed plan, in contrast, does not restrict it from using the incremental capital module to obtain supplemental capital revenue even if its X factor is materially negative.
b) Is Enbridge Gas prepared to limit its use of the ICM if it obtains the negative X factor that BV proposes? If so, in what way?
c) Is Enbridge Gas prepared to limit its use of the ICM if it is permitted to operate under an Alberta-style K-bar mechanism? If so, in what way?

d) In California, the capex budgets of utilities in multiyear rate plans are sometimes based on a repetition of the budget approved for the forward test year. Would Enbridge Gas be prepared to limit its use of the ICM if it could obtain such a budget, as escalated for construction cost and customer growth? If so, in what way?
e) Does Dr. Kaufmann believe that limiting Enbridge Gas's capital revenue to that provided by its proposed X factor and/or an Alberta-style K-bar adjustment is a better approach to ratemaking than Enbridge Gas's proposed use of the ICM?
f) Does Dr. Kaufmann believe that the approach to calculating K bar used in Massachusetts generates capex containment incentives that are as strong or stronger than those generated by an Alberta-style K bar?

10.1-Staff-68

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 33

BV states that

> The following formula was used to compute values of the capital quantity index:
>
> $$XK_t = XK_{t-1}*(1-d_t) + (\text{Capital Additions}_t/PK_t).$$
>
> Here, the quantity of capital input in year t is equal to capital quantity in the previous year t-1, minus the depreciation on the preceding year's capital quantity, plus capital additions in year t deflated by an asset price index in year t (PK_t).

a) Is this formula part of the hyperbolic decay specification?
b) Why does the text refer repeatedly to depreciation rather than physical decay of the stream of capital services?

10.1-Staff-69

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 33

BV states that

> In constructing capital quantity and cost indices for the US sample, we took 1998 as the benchmark year. We estimated the benchmark capital value by subtracting accumulated depreciation in 1998 from 1998 gross plant for both distribution and general plant and adding distribution plus general net plant values together. This sum was then divided by a "triangularized" weighted average of the values of the producer price index.

a) Please confirm that, with a relatively recent 1998 benchmark year for capital quantity calculations, the benchmark year calculations have some influence on BV's TFP growth calculations, which begin in 2007.
b) Under hyperbolic decay, is it a better approach to use *gross* or *net* plant value to calculate the first-year capital stock? Why is that approach most appropriate?
c) Which approach causes TFP to rise more slowly?

10.1-Staff-70

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 34

BV states that

> Dr. Kaufmann has interacted with utility engineering and operational professionals many times, and in diverse locations, over the last 25 years. These experts overwhelmingly believe that gas distribution assets show little physical decay or loss of efficiency in the years immediately after they are put in place. Instead, the industry's accumulated experience is that newly-installed gas distribution assets are "like new" for several, and sometimes many, years. However, as assets progress towards the end of their useful lives, they begin to perform less efficiently, and efficiency losses accelerate as assets approach the time when they are retired.
>
> This accumulated industry expertise is essentially the opposite of how assets depreciate under Geometric decay. Geometric decay assumes that assets decline at a constant percentage rate every year they are in use.

a) Please confirm that, in a statistical utility cost benchmarking study, the salient issue in choosing a capital cost specification is the typical pattern of decay in the service flow of a *cohort* of assets with diverse service lives, and not the decay patterns of *individual* assets such as a service line.
b) Indexed attrition relief mechanisms play the role of accelerating rates or revenue between rate rebasings that are based on cost of service (COS) accounting. COS accounting entails historical plant valuations and straight-line depreciation of asset value. The return on each asset accordingly shrinks over time so that the cost of owning a 25-year asset is much lower than the cost of a new asset. Would this be considered pertinent in selecting a capital cost specification for a productivity trend study that is used for X factor calibration?
c) In his work for the OEB, did Dr. Kaufmann sometimes use a COS approach to capital cost and quantity measurement that was expressly designed to mirror COS accounting? If yes, please indicate in which studies did Dr. Kaufmann use a COS approach?

10.1-Staff-71

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 36

BV states that “Drawing on the most recent National Grid precedent, the service life for assets is 51 years.”

a) What is the average service life of Enbridge Gas assets?
b) Has this changed materially over time? If yes, please explain how it has materially changed?

10.1-Staff-72

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 1, p. 37

BV states that:

> For every sampled gas distributor, total O&M expenses were computed as:
>
> Total Distribution O&M Expenses plus
>
> Total Underground Storage Expenses plus
>
> Total Other Storage Expenses plus
>
> Customer Service & Information Expenses plus
>
> Customer Accounts Expenses plus
>
> Sales Expenses minus
>
> Franchise Requirements (acct 927) minus
>
> Maintenance of General Plant (acct 932) minus
>
> Uncollectible Accounts (acct 904) minus
>
> Proxy for DSM expenses (acct 905 for MA distributors, acct 908 for all others) plus
>
> Allocated A&G expenses, equal to total gas A&G multiplied by (Gross gas distribution plant divided by total gas plant), in each sample year

The working papers provided by BV seem to indicate that pensions and other benefits are included in the cost calculations for both the US and Enbridge Gas.

The cost definition as described appears to reduce included cost by expenses for franchise requirements and maintenance of general plant and then to add in an allocated share of those expenses at a subsequent step.

a) Please confirm that BV’s statistical benchmarking study included pension and benefit expenses. Given the differences in the healthcare and pension systems between the US and Canada, doesn't it make more sense to remove these costs from both the US and Enbridge Gas calculations?

b) Is Enbridge Gas proposing to address at least some pension and benefit expenses through the pension and other post employment benefits variance account?

c) Why remove maintenance of general plant?

d) Is the description of the treatment of franchise requirements and maintenance of general plant described above correct?

    i. If so, why remove maintenance of general plant and franchise requirements before allocating a share of A&G expenses?

    ii. If not, what is the correct definition of O&M expenses for the BV study?

e) Six distributors show the same number of customers for 2022 as in 2021 and appear to be imputations (AGL, BGE, NIPSCO, NSPWI, PSNC, South Jersey). What are the correct 2022 values for those distributors?

f) Do the total customers used in the analysis include both bundled service and unbundled transportation-only customers?

g) Please provide any analysis that BV undertook showing that DSM expenses are limited to account 905 for Massachusetts distributors and account 908 for all others.

10.1-Staff-73

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 2

BV calculated a productivity trend for US distributors starting with the 2006-2007 growth rate.

a) The working papers appear to have all the required data to calculate including the 2005-2006 growth rate. Why was that year not included in the trend?
b) Please recalculate the trend including this growth rate.

10.1-Staff-74

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 2

BV calculates an average real rate of return for US distributors in cell CR2 of the Calculation worksheet provided with the working papers.

a) Please provide reasons for the use of an average real return in the capital price formula versus a rate of return that varies by year.

a) Please also provide the rationale for ending this average in 2020 as opposed to 2022.

10.1-Staff-75

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 2

The working papers provided by BV show the construction of a national Handy Whitman index from the six regional indexes. The working papers do not show how those regional indexes were constructed (e.g., there is no Handy Whitman index for total gas distribution plant for any of the six regions or nationally).

a) Please provide a rationale for why the regional variation was suppressed and a national index used when input quantity growth was measured as a cost-weighted average of results for individual companies.
b) Why is it reasonable to take a simple average of the six regions to arrive at national index when the number and size of distributors differs by region?
c) Please provide the underlying calculations for the regional total gas distribution plant asset price indexes.
d) What weights were used to construct regional indexes of total gas distribution plant indexes and why were those weights chosen?

10.1-Staff-76

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 2

Attachment 2 features a workbook link to an external file named USGasTFPstudy_03132024 RZ.xlsx.

Please provide this file.

10.1-Staff-77

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 2

The working papers provided by BV show the calculation of US industry TFP growth from aggregated data.

a) Apart from the 4GIR Ontario TFP precedent, is there a reason why it was preferable to aggregate the US data and then calculate TFP as opposed to calculating TFP trends of individual companies and then aggregating these results using either simple or cost-weighted averages?

b) It appears that the input quantities are aggregated using the cost weights and the output quantities are just the sum of customers which is implicitly a weighting by customer shares. Please provide a rationale for using different weighting methods the outputs and inputs used in the TFP calculation.

10.1-Staff-78

Ref: Exhibit 10, Tab 1, Schedule 1, Attachments 2 and 3

BV benchmarked the cost performance of EGI over the 3 years from 2000 to 2022.

a) Why did BV not provide productivity growth or benchmarking results for EGI's forecasted 2023 costs and its proposed 2024 revenue requirement?
b) Is this consistent with price cap regulation of power distributors in Ontario?
c) Was a benchmarking of the proposed 2024 revenue requirement not required to ascertain customer benefits from the rebasing?

10.1-Staff-79

Ref: Exhibit 10, Tab 1, Schedule 1, Attachments 2 and 3

The working papers provided by BV indicate that the Handy-Whitman index is used as the asset price in US capital price and cost calculations whereas the "GDP-IPD" is used for Enbridge Gas.

a) In the context of unit cost benchmarking vs. US peers, please comment on the impact of using an industry-specific price for the US vs. a macro inflation measure for Enbridge Gas. How would the benchmarking results differ if the Handy Whitman index for the North Atlantic region was used for Enbridge Gas?
b) Please clarify what asset price index was used for Enbridge Gas.

10.1-Staff-80

Ref: EB-2024-0111, Phase 2 Exhibit 10, Tab 1, Schedule 1, Attachments 2 and 3.

BV's working papers for Enbridge Gas lacked some of the supporting information for the calculation of the benchmark year capital stock. The calculation of the triangularized weighted average was not included. Cells G6-H6 of BV's working paper Attachment 3 suggests that BV used a 38-year triangularized weighted average to calculate Enbridge Gas's benchmark year capital stock while column J of that file indicates that a 51-year average service life was assumed for subsequent years of the sample period for Enbridge Gas's assets. Similar capital stock calculations are shown in columns BI – DF of the Attachment 2 "Calculations" worksheet.

a) Please confirm that 38 years was used to calculate Enbridge Gas's triangularized weighted average. Is this the same as was done for the US gas distributors? If not, why not?

b) Why were different lengths used for the triangularized weighted average in the benchmark year than for all the other years of the study?

c) Please provide the detailed calculations supporting the triangularized weighted average for Enbridge Gas and list the inflation measure for the calculations.

d) Why were the average service lives for total regulated gas plant and distribution plant assumed to be the same?

e) Why is a 51-year average service life assumed?

f) For the US a 51 year triangularized weighted average asset price for the benchmark was used. Some of the calculations in the working papers seem to show a 40-year life for US companies subsequent to the benchmark year. Is 40 years the assumed service life and is it being used consistently throughout the service price calculations after the benchmark year? Please explain why the service life assumption for the benchmark year should be different from the assumption after the benchmark year.

g) Please show where the calculations behind the "Efficiency Depreciation Hyperbolic" values in the calculation worksheet of Attachment 2 can be found or provide these calculations.

h) On the Attachment 2 Calculations worksheet, please explain why the pasted "Capital Input Quantity" values differ from the "Capital Stock Hyperbolic" calculations.

10.1-Staff-81

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 3

Column AG of this portion of the BV working papers provides the calculation of real capital additions for Enbridge Gas which flow into the capital stock calculations. For all regulated operations calculations, these appear to have been calculated by dividing the current year distribution and other plant additions by the prior year value of the GDP-IPD. For the distribution only calculations, the current year value of distribution and allocated general plant additions is divided by the current year value of the GDP-IPD.

Which of these calculations is correct?

10.1-Staff-82

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 3

PEG needs additional data for Enbridge Gas to further its statistical benchmarking research.

a) Please provide the following data for each year of the 2006-2022 sample period.
   1) Gross value of total regulated plant
   2) Gross value of regulated transmission plant
   3) Gross value of regulated storage plant
   4) Gross value of distribution plant
   5) Miles of transmission mains
   6) Miles of distribution mains
   7) Share of distribution mains in service that were installed before 1950 and before 1940
   8) Customer volumes by customer class (e.g., residential, commercial, industrial, generation, total)
   9) Customer numbers by customer class (e.g., residential, commercial, industrial, generation, total)

10.1-Staff-83

Ref: Exhibit 10, Tab 1, Schedule 1, Attachment 3; EB-2022-0200, Exhibit 4, Tab 4, Schedule 2, p. 4 and EB-2022-0200, Exhibit 2, Tab 2, Schedule 1, Attachment 6

BV's working papers specific to Enbridge Gas in Attachment 3 are lacking the level of detail that BV provided for the US sample. For example, O&M expenses are provided in a hard coded form (e.g., Columns BW and CB), without providing details of the accounts that were included or excluded from the research. Similarly, the working papers do not provide supporting calculations for the A&G expense allocator. These limitations restrict the ability of third parties to validate the data and to evaluate alternative cost definitions.

A preliminary check of O&M expenses and plant additions against historical data provided in EB-2022-0200 has led to concerns about the accuracy of the data entry of both plant additions and O&M expenses and the consistency of the O&M cost definitions between the US sample and Enbridge Gas. For example, the sum of BV's labor and non-labor O&M in 2018 appears to be greater than the Enbridge Gas's non-capitalized Utility O&M expenses excluding integration and DSM expenses as reported in EB-2022-0200 Exhibit 4, Tab 4, Schedule 2, p. 4. The BV distribution plant addition value for 2022 is $436 million ($510.2 million including allocated general plant, while Enbridge Gas reported 2022 distribution plant additions for the EGD rate zone alone of $595.1 million or $1,031.1 million for the entirety of EGI in EB-2022-0200, Exhibit 2, Tab 2, Schedule 1, Attachment 6.

The BV working papers show an unusual blip in distribution capital additions in 2016 which is not repeated.

PEG notes that a large share of non-labor O&M expenses are incurred for outsourced services.

a) Please provide non-capitalized O&M expenses by function separately (e.g., in a form similar to the Ontario power distributors' RRR filings) for Enbridge Gas, EGD, and Union Gas for the 2006-2022 period.
b) Please provide the detailed calculations supporting the calculation of distribution and all regulated operations O&M for the 2006-2022 period. This would include any allocations of A&G expenses.
c) Please provide annual values for the following non-capitalized O&M cost categories for the 2006-2018 period: pensions and benefits, uncollectible bills, customer service and information, gas transmission by others, compressor station fuels, DSM expenses, franchise fees, and maintenance of general plant for Enbridge Gas, EGD, and Union Gas for the 2006-2022 period. Please also identify the function to which each of these cost categories is assigned.
d) Please provide plant additions by function (e.g., in a form similar to the Ontario power distributors' RRR filings) for the 1998-2022 period, for Enbridge Gas, EGD, and Union Gas. Please make sure to itemize transmission and storage plant.
e) Why is the general plant allocator allowed to vary for the US sample while the general plant allocator for Enbridge Gas is fixed at the 1998 value?
f) Please discuss how O&M expenses were addressed in the year of the merger between EGD and Union Gas.
g) What is the cause of the blip in Enbridge Gas plant additions in 2016?
h) Please explain the data abnormalities for 2018 labor and non-labor O&M and 2022 distribution plant additions discussed in the preamble. Are other years similarly affected?
i) What kinds of O&M expenses are considered integration-related costs?

j) For a recent year, please provide the percentage of non-labor O&M expenses that were outsourced services. Does Enbridge Gas believe that this percentage has increased, decreased, or stayed about the same during the 2006-2022 period?

10.1-Staff-84

Ref: Exhibit 10, Tab 1, Schedule 1, Attachments 1-3

A number of concerns have been raised in these questions that might lead BV to clarify or make modifications to their calculations.

In the event that BV decides it wishes to clarify or modify the calculations provided with the working papers, PEG requests that a revised version of the working papers be provided for additional review in preparation for the technical conference.