EB-2024-0111

Current Energy Group Responses to Interrogatories on Exhibit M2

September 6, 2024

M2.EGI-1

Question:

(a) Please provide a list of all proceedings where Matthew McDonnell and Brad Cebulko have been qualified as experts in cost of capital matters. Please provide links to that expert evidence.

Response:

As shown in the resumes filed in the docket, Mr. McDonnell and Mr. Cebulko have extensive experience testifying before and advising state commissions on rate case proceedings. In every case Mr. McDonnell and Mr. Cebulko has submitted testimony on behalf of a client and the state commission has accepted their testimony into the record. Mr. Cebulko has testified on issues including cost of service, rate design, time-of-use rates, gas and electric plant prudency, performance metrics, performance incentive mechanisms, gas supply prudency, electric and gas service quality metrics, gas system planning, gas line extension allowances, prudency of gas alternative fuel programs, gas demand response programs, non-pipeline alternatives, and building electrification programs. Please see Mr. Cebulko testimonial engagements in his resume.

In addition to Mr. Cebulko's resume, Mr. Cebulko has recently submitted the following testimonies:

- Puget Sound Energy 2024 Gas and Electric General Rate Case (DKT: UE-240004 and UG-240005) on Behalf of the Joint Environmental Advocates. Mr. Cebulko testified on electrification programs, alternative fuel program prudency, gas capital expenditure alternatives analysis, and differentiated ROE. Available at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=1979&year=2024&docketNumber=240004
- Northern States Power Company 2024 Natural Gas Rate Increase Application (DKT: 23-367) on Behalf of AARP. Mr. Cebulko testified on the appropriate cost of service study and residential rate design. Available at: https://apps.psc.nd.gov/webapps/cases/psdocketsearch#searchanchor

Mr. McDonnell's experience has been focused more on the provision of expert advice directly to state commissions. Mr. McDonnell served as Commission Counsel to the Hawaii Public Utilities Commission from 2015 – 2019 where he advised the commissioners on all aspects of a rate case proceeding. Since then he has advised other commissions as an external expert on incentive rate-making. Moreover, Mr. McDonnell has worked extensively on matters related to utility financial incentives and ways in which utility revenues can be better tied to outcomes aligned with the public interest.

CEG's evidence is on incentive rate-setting mechanisms, particularly in relation to the energy transition and capital cost containment. Mr. McDonnell and Mr. Cebulko have provided evidence and/or advised commissions on that topic, which in many cases has also touched on sub-topics such as the cost of capital, revenue decoupling, ECMs, connection cost recovery, gas supply incentive mechanisms, and IRP incentives. However, Environmental Defence is not seeking to have Mr. McDonnell and Mr. Cebulko approved as experts in in each of those sub-topics. For instance, although Mr. McDonnell and Mr. Cebulko have provided testimony and/or advice to commissions on the cost of capital as part of broader evidence in incentive rate-setting mechanisms, they are not put forward as experts who would, for example, recommend a specific value for the fair and appropriate return on equity for a utility.

M2.EGI-2

Questions:

(a) Please provide a list of proceedings before energy regulators in Canada or the United States where differentiated ROE was proposed and approved. Please summarize the request and approval in each such case and provide a link to the regulator's decision and key evidence.

(b) Please provide a list of proceedings before energy regulators in Canada or the United States where differentiated ROE was proposed and not approved. Please summarize the request and decision in each case and provide a link to the regulator's decision and key evidence.

Responses:

These questions are beyond the scope of evidence that CEG has been asked to prepare and far beyond what could be prepared with the proposed budget and time available for interrogatory responses. A review of all jurisdictions in North America as requested by this question would be very time and resource intensive if done in a comprehensive way. However, CEG identifies the following proceedings where the issue is being considered:

- The Hawaii Public Utilities Commission is authorized to consider the establishment of differentiated authorized rates of return on common equity to encourage increased utility investments in transmission and distribution infrastructure, discourage an electric utility investment in fossil fuel electric generation plants. The differentiated authorized rates of return are statutorily authorized as a mechanism by which to incentivize grid modernization and disincentivize fossil generation, respectively.[1]
- FERC conditionally approved a 50-basis point ROE adder for Orange and Rockland Utilities' transmission facilities that participated in a Regional Transmission Organization.[2]
- Mr. Cebulko recommended the Washington Utilities and Transportation Commission set the ROE for Puget Sound Energy's customer request and capacity expansion gas projects 0.75 percent lower than its approved ROE for all other gas capital investments.[3]
- In July 2024, Colorado Public Utilities Commission (CoPUC) Staff proposed that the Colorado Public Utilities Commission reduce the Public Service Company of Colorado's ROE for new growth and capacity expansion projects (growth investments) in the gas utility business.[4]

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[1] HI Rev Stat § 269-6e(4) (2023). Available at: https://law.justia.com/codes/hawaii/title-15/chapter-269/section-269-6/.

[2] FERC. Order on Tariff Filing, Establishing Paper Hearing Procedures, and Establishing Hearing and Settlement Judge Proceedings. Docket No. ER-24-1614-000. Issued May 24, 2024. Available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240524-3049&optimized=false. P. 2.

[3] Bradley Cebulko. Response Testimony (Nonconfidential) on Behalf of Joint Environmental Advocates. 2024 PSE General Rate Case. Docket Nos. UE-240004 and UG-240005 (Consolidated). Available at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=1979&year=2024&docketNumber=240004 . p.3.

[4] Proceeding No. 24AL-0049G, In the Matter of Advice No. 1029-Gas of Public Service Company of Colorado to Revise its Colorado PUC No. 6-Gas Tariff to Increase Jurisdictional Base Rate Revenues, Implement New Base

M2.EGI-3

Question:

(a) Please provide the letter of engagement, terms of reference and scope of work related to the Current Energy Group (CEG) report filed in this proceeding.

Response:

This can be found in the June 11, 2024, letter provided to the OEB outlining the proposed evidence.

Rates for all Gas Rate Schedules, and Make Other Proposed Tariff Changes Effective February 29, 2024. Answer Testimony of Erin T. O'Neill, July 11, 2024.

M2.EGI-4

Reference: EB-2024-0063

Question:

(a) Please confirm that CEG is aware that the OEB is currently conducting a generic proceeding on cost of capital. Please confirm that CEG has not provided evidence in that proceeding.

Response:

CEG is aware of the generic proceeding. CEG confirms that it has not provided evidence in that proceeding.

M2.EGI-5

Question:

(a) Please reconcile the concept of a differentiated ROE with the OEB's legal requirement to ensure that the Fair Return Standard is met.

Response:

A fair return does not require an equal return on equity for all investments. Regulators have approved incentive rates of return for certain types of investments. As such, it is reasonable that the inverse – a reduced return on equity for certain types of investments – may also be reasonable. To ensure a fair overall return, a reduced return for one type of asset may need to be made up for with an increased return or earnings opportunities for other asset types or other compensatory factors (e.g. risk reduction). See our evidence for details and proposals in that regard.

This response should not be taken as a legal opinion, which would be beyond the scope of our evidence and expertise.

M2.EGI-6

Question:

(a) Please provide all analysis prepared by CEG demonstrating that a differentiated ROE meets the Fair Return Standard.

Response:

See the response to M2.EGI-5 and pages 11 and 12 of the CEG evidence.

M2.EGI-7

Reference: Exhibit M2, page 11

Preamble: CEG states: "Under a differentiated ROE approach, Enbridge Gas would continue its mandated obligation to serve natural gas customers with a safe and reliable gas system without subsidizing unreasonable growth investments that impact a diminishing customer base over the coming decades."

In practice, any given asset may address both growth and reliability objectives. For example, Enbridge Gas may schedule the replacement of a distribution main in order to address reliability concerns; at the same time, the continued operation of this distribution main may also facilitate customer growth.

Question:

(a) How would CEG propose that this asset investment be treated in its ROE framework?

Response:

One option would be to characterize each investment on whether its primary purpose is system expansion or reliability. Alternatively, an asset could be classified as a growth asset if it *increases* capacity to connect new customers or allow for expanded consumption from existing customers (e.g. new pipes or larger pipes). Pre-existing Enbridge asset classifications may be sufficient.

M2.EGI-8

Question:

(a) Please provide a list of all proceedings where Matthew McDonnell and Brad Cebulko have been qualified as experts in revenue decoupling or similar rate design proposals for fixed revenue by rate class. Please provide links to that expert evidence.

Response:

See M2.EGI-1.

M2.EGI-9

Reference: Exhibit M2, pages 13 to 14

Preamble: CEG states: "Given the concern that the energy transition is expected to result in declining sales from small-volume customers, an average use variance, or revenue per customer decoupling mechanism, may not adequately address the utility's financial exposure to a decline in the number of customers. In lieu of an average use variance account, the OEB should consider an alternative approach – revenue per customer class. Like revenue per customer, revenue per customer class determines the appropriate revenue to be collected regardless of the level of demand from customers. Revenue per customer class, on the other hand, is indifferent to the number of customers on the system or to average customer use.

To address the OEB's expectation of declining sales from small-volume customers, the OEB should explore a harmonized revenue balancing account that allows for truing up collected revenues against allowed revenues in a manner that is not tied to customer counts or customer average use."

Questions:

(a) Please provide any references to gas utilities/jurisdictions that have revenue true-up mechanisms by revenue/rate class, including a link to the regulator's decision and key evidence.
(b) For any references provided, please indicate if the utility is a provider of both natural gas and electricity services.
(c) For any references provided, please also indicate whether the utility is subject to weather risk or not. If yes, does that mean a weather normalization adjustment is performed for each respective rate class before the true-up is calculated?
(d) For any references provided, please also indicate what type of rate setting mechanism is employed (i.e. cost of service, price cap, or another form of incentive regulation).
(e) Finally, if an incentive regulation rate setting mechanism is employed, please indicate if customer numbers and associated volumes are updated annually as part of the rate setting process.

Responses:

These questions are beyond the scope of evidence that CEG has been asked to prepare and far beyond what could be prepared within the proposed budget and time available for interrogatory responses.

However in response, the Hawaii Public Utilities Commission includes revenue decoupling to true up collective revenues to an annual revenue target in its establishment of a Performance-Based Regulation framework.[5]

[5] Hawaii Public Utilities Commission. Summary of Phase 2 Decision & Order Establishing a PBR Framework. December 23, 2020. Available at: https://puc.hawaii.gov/wp-content/uploads/2020/12/PBR-Phase-2-DO-5-Page-Summary.Final_.12-22-2020.pdf. p. 3.

M2.EGI-10

Reference: Exhibit M2, pages 13 to 14

Preamble: CEG states: "Given the concern that the energy transition is expected to result in declining sales from small-volume customers, an average use variance, or revenue per customer decoupling mechanism, may not adequately address the utility's financial exposure to a decline in the number of customers. In lieu of an average use variance account, the OEB should consider an alternative approach – revenue per customer class."

Questions:

(a) Please provide further details of how the revenue per customer class would work under Enbridge Gas's proposed/historical IRM frameworks.
(b) Please confirm why CEG is proposing a revenue decoupling mechanism as part of Phase 2 rather than in Phase 1 or Phase 3.
(c) Please confirm, if Enbridge Gas forecasts net customer growth over the IRM period the Company will lose revenue under CEG's revenue decoupling proposal in this scenario.
(d) Please confirm, if customers leave Enbridge Gas's system during the IRM period the average customer's bill will increase to make up for the shortfall in revenue (all else being equal).
(e) Please confirm the revenue decoupling proposal suggested by CEG is specific to in-franchise low-volume rate classes (residential, general service).

Responses:

(a) CEG directs Enbridge to Exhibit M2, pages 13 to 14. Further details of the revenue decoupling mechanism design and a more detailed accounting of its interface with Enbridge Gas's proposed/historical IRM frameworks are beyond the scope of evidence that CEG has been asked to prepare and beyond what could be prepared within the proposed budget and time available for interrogatory responses.
(b) CEG was engaged to provide its expert opinion and prepare evidence for Phase 2 of this proceeding. CEG views revenue decoupling mechanism design as core to its evaluation of incentive-based regulatory structures and their respective alignment with the public interest in the context of a dynamic energy transition. CEG would be open to providing further evidence during Phase 3 of this proceeding if asked to do so but finds the design of a decoupling mechanism relevant to Issue #2 of Phase 2 and thus worth introducing at this juncture.
(c) CEG cannot confirm with specificity whether or not Enbridge would "lose revenue" under CEG's revenue decoupling proposal if Enbridge Gas forecasts net customer growth over the IRM period. In general, CEG's proposed revenue decoupling design is intended to provide an annual true-up of actual revenues collected to match target revenues over that same period on a per-customer class basis. The net effect of such an approach would be to lower the overall risk of revenue under collection rather than increase it.

(d) CEG can confirm that, generally speaking, revenue decoupling mechanisms operate to "true-up" a utility's actual revenues when forecasted sales exceed actual sales. The true-up component of a revenue decoupling mechanism would operate to place a small upward adjustment on customers' bills to close that gap. In this sense, it would operate like the current per-customer variance account, which could also operate to increase a customer's bill under certain circumstances.

(e) CEG's revenue decoupling proposal does not specify whether it should be limited to in-franchise low-volume rate classes (residential, general service). There should not be structural limitations to applying the approach across all customer classes. That said, CEG would need to conduct further analysis to determine whether it may be appropriate to limit the decoupling mechanism design proposed to in-franchise low-volume rate classes.

M2.EGI-11

Reference: Exhibit M2, page 12

Preamble: CEG states: “However, revising the rate structure to collect a greater share of revenues via fixed rates is not an appropriate solution. A high fixed charge approach to addressing the throughput incentive would undermine customers’ incentive to conserve energy and impose greater costs on low-usage (and often low-income) customers.”

Questions:

(a) Please confirm if CEG considered direction and decisions from previous OEB consultations about rate design, incentive regulation plans, conservation programs or other items in developing its revenue decoupling proposal.
(b) If the answer to part a) is yes, please indicate the references to OEB work and explain what CEG considered and how this was taken into account in the CEG evidence.
(c) Please confirm how the OEB addressed the undermining of customers’ incentive to conserve energy when fully fixed distribution charges were implemented for electricity residential customers.
(d) Please confirm if CEG considered how the Demand Side Management (DSM) Framework and the DSM Incentive Deferral Account incentivizes Enbridge Gas to promote energy conservation.

Response:

CEG is unable to answer these questions without a specific list of directions and decisions that the Company is asking about. CEG did review and consider the decision from the first phase of this proceeding.

M2.EGI-12

Question:

(a) Please provide a list of all proceedings where Matthew McDonnell and Brad Cebulko have been qualified as experts in efficiency carryover mechanisms (ECM). Please provide links to that expert evidence.

Response:

See M2.EGI-1.

M2.EGI-13

Question:

(a) Please provide examples of other Canadian or American jurisdictions that have implemented an ECM and provide any examples that CEG endorses.

Response:

This question is beyond the scope of evidence that CEG has been asked to prepare and beyond what could be prepared with the proposed budget and time available for interrogatory responses. However, we can provide a few examples:

1. The British Columbia Utilities Commission determined a four-step process to formalize ECM applications in its 2020 Decision of FortisBC Energy and FortisBC's 2020-2024 Multi-Year Rate Plan.[6]

2. The Alberta Utilities Commission implemented an ECM in its first and second Multi-Year Rate Plan terms for electric and gas distribution utilities and is considering the reimplementation of an ECM in its fourth Multi-Year Rate Plan term.[7]

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[6] BCUC. Decision of Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024 of FortisBC Energy Inc. and FortisBC Inc. Orders G-165-20 and G-166-20. June 22, 2020. Available at: https://docs.bcuc.com/documents/decisions/2020/doc_58466_2020-06-22-fortisbc-mrp-2020-2024-decision.pdf, p. 87.

[7] Alberta Utilities Commission. 2024-2028 Performance-Based Regulation Plan for Albedrta Electric and Gas Distribution Utilities. Decision 27388-D01-2023. October 4, 2023. Available at: https://ucahelps.alberta.ca/documents/27388_X%5b%5d_27388-D01-2023%202024-2028%20PBR%20Plan%20for%20Alberta%20Electric%20and%20Gas%20Distribution%20Utilities_000882.pdf. P. 95-98.

M2.EGI-14

Reference: Exhibit M2, page 1 and page 14

Preamble: At page 1, CEG states: "The OEB should implement an efficiency carryover mechanism to resolve a flaw in the standard price-cap approach whereby utilities lose the incentive to implement cost containment measures near the end of the rate term (because they have fewer years remaining, if any, to benefit from cost-containment). This mechanism functions by allowing the utility to benefit from savings that are carried over into the new rate term. In addition, a calibrated efficiency carryover mechanism that includes capex efficiency sharing could operate to mitigate Enbridge Gas's capital expenditure investment preference."

ECMs are potentially valuable tools for encouraging companies to pursue efficiency gains in every year of an IRM. However, ECMs are complex and can be difficult to design.

Drawing in part on the experience in Australia, CEG has recently recommended that the OEB implement ECMs.

Questions:

(a) Is CEG aware that ECMs in Australia (and the UK) were an outgrowth of the UK "building block" model of incentive regulation? Does Current Energy believe ECMs will fit easily into a North American style, productivity-based IRM? Please explain why or why not?
(b) Does CEG believe the evidence from Australia implies that ECMs have been more successful for Opex applications rather than Capex applications? Please explain.
(c) ECMs pose several challenging implementation issues. Does CEG have any opinions on the eight implementation issues identified below? If so, please explain how CEG can address each issue.

   i. Should an Opex ECM only be proposed, or should a Capex ECMs be proposed as well?
   ii. How will Opex efficiencies be measured under the ECM?
   iii. How will Capex efficiencies be measured under the ECM?
   iv. How exactly should efficiency gains be distributed to customers over the term of a successor IRM?
   v. Should there be a "zero floor" on ECM benefits?
   vi. If so, should that floor apply to each individual ECM, or the sum of the two ECMs?

(d) Should the introduction of an ECM have any impact on the "stretch factor" in an IRM? If so, please explain how.

Responses:

This question is beyond the scope of evidence that CEG has been asked to prepare and beyond what could be prepared with the proposed budget and time available for interrogatory responses. However, CEG acknowledges that ECMs can be complex and encompass numerous design decisions depending upon how an ECM is structured. Ultimately, whether an ECM's complexity is outweighed by the value it can provide within an IRM framework is dependent upon the portfolio of regulatory mechanisms that make up the IRM and how such mechanisms balance and complement one another. CEG observes that ECMs have been acknowledged to have conceptual merit within North American multi-year rate plans, including by the OEB and the Alberta Public Utilities Commission.

M2.EGI-15

Question:

(a) Please provide a list of all proceedings where Matthew McDonnell and Brad Cebulko have been qualified as experts in connection cost recovery mechanisms. Please provide links to that expert evidence.

Response:

See M2.EGI-1.

M2.EGI-16

Questions:

(a) Please provide a list of proceedings where the connection cost recovery mechanisms similar to those proposed by CEG in its evidence have been approved by an energy regulator in Canada or the United States. Please summarize the request and approval in each such case and provide a link to the regulator's decision and key evidence.
(b) Please provide a list of proceedings where similar connection cost recovery mechanisms were proposed and not approved. Please summarize the request and decision in each case and provide a link to the regulator's decision and key evidence.

Responses:

It is not clear which mechanisms the Company is referring to.

M2.EGI-17

Reference: Exhibit M2, page 16

Preamble: CEG states: "Enbridge currently has an incentive to include connection costs in rate base instead of having them covered by CIACs. Enbridge earns a profit on the former, but not the latter. This incentive is large because the magnitude of connection capital costs included in rate base is approximately $250 million annually."

Question:

(a) Would ED consider this an issue to be included in the expected generic proceeding addressing revenue horizon?

Response:

We have understood this to be a question to Environmental Defence, not to CEG. It is not clear whether this issue will be within the scope of the generic proceeding addressing the revenue horizon.

M2.EGI-18

Question:

(a) Please provide a list of all proceedings where Matthew McDonnell and Brad Cebulko have been qualified as experts in gas supply incentive mechanisms. Please provide links to that expert evidence.

Response:

See M2.EGI-1.

M2.EGI-19

Questions:

(a) Please provide a list of proceedings where the gas supply incentive mechanisms similar to what CEG propose have been approved by an energy regulator in Canada or the United States. Please summarize the request and approval in each such case and provide a link to the regulator's decision and key evidence.
(b) Please provide a list of proceedings where similar gas supply incentive mechanisms were proposed and not approved. Please summarize the request and decision in each case and provide a link to the regulator's decision and key evidence.

Responses:

This request is unreasonably burdensome as it would require a review of all gas regulatory proceedings in all jurisdictions across North America to determine whether similar mechanisms were proposed and the outcome in each case.

M2.EGI-20

Reference: EB-2017-0129, Report of the Ontario Energy Board, Framework for the Assessment of Distributor Gas Supply Plans, pages 7 to 8.

Preamble: "The OEB is of the view that a principle-based approach to gas supply planning is an effective means of guiding the distributors' approach to developing a gas supply plan that is consistent with the outcomes customers' desire."

"The guiding principles for a distributor's gas supply plan are to deliver gas supply that is cost-effective, reliable (secure) and achieves public policy objectives."

"For clarity, cost-effectiveness does not necessarily mean the "lowest cost," reliability does not mean "reliable at any cost" and support for public policy does not mean "support at any cost" or "any level of reliability." Rather, the intent is to strike a balanced approach to the benefit of customers."

Question:

(a) Please discuss why a gas supply cost sharing mechanism is appropriate for utilities, such as Enbridge Gas, that are required to balance the OEB's guiding principles in its gas supply purchases where the principle of cost-effectiveness does not mean the "lowest cost".

Response:

The OEB's policy as noted above is consistent with other jurisdictions that consider cost, risk, and public policy objectives when determining if a utility action, program, or project is in the public interest. CEG does not see a conflict between its recommendation and the OEB's stated principle-based approach. Rather, a gas supply cost-sharing mechanism is a tool that can help the Commission better align the utility's incentives with the principle-based approach it articulated. The tool described in CEG's report encourages the Company to be mindful of costs and risks of its supply strategy as it will also be financially impacted by its decisions and strategy along with its customers.

M2.EGI-21

Reference: EB-2017-0129, Report of the Ontario Energy Board, Framework for the Assessment of Distributor Gas Supply Plans, page 1.

Preamble: "The Ontario Energy Board (OEB) has developed a Framework for the Assessment of Distributor Gas Supply Plans (the Framework). The Framework sets out the OEB's approach for the assessment of the cost consequences of rate-regulated natural gas distributors' (distributors) gas supply plans. The Framework will ensure that there is transparency, accountability, and measurability regarding the distributors' gas supply plans to assure they deliver value to consumers."

Question:

(a) Given that the OEB has a process for gas supply planning that applies to all utilities in the province, why is this topic relevant in this proceeding which includes only Enbridge Gas?

Response:

CEG has no views on regulatory questions around which proceeding is most appropriate to implement gas supply incentive mechanisms. However, our recommendations are relevant to the overall question of which incentive structures are most appropriate in the context of the energy transition.

M2.EGI-22

Reference: Exhibit M2, page 18

Preamble: CEG states: "Although gas supply costs are not entirely under Enbridge Gas's control, the company generally can negotiate more favorable gas supply contracts and take steps to reduce the amount of gas supply needed to meet demand (e.g., by working to conserve energy, shift demand, or facilitate electrification alternatives). In contrast, customers have little ability to manage gas supply cost risk – yet the current QRAM unfairly shifts this risk entirely onto their shoulders."

Questions:

(a) Please confirm that CEG is aware that Enbridge Gas's gas supply contracts are tied to price indices and basis differentials at various market hubs.
(b) Pease confirm that CEG is aware that Enbridge Gas relies heavily on market area gas storage for meeting fluctuations in demand rather than just in time gas purchases.
(c) Please confirm that deregulation of the natural gas market in Ontario provided customers with the option to obtain their natural gas supply from natural gas retailers and that customers are not captive to the natural gas commodity charges of Enbridge Gas.

Responses:

(a) CEG is aware that Enbridge has structured its gas supply contract to be tied to price indices and basis differentials at various market hubs. CEG is unaware of any OEB regulation that requires Enbridge to tie all its gas supply contracts to price indices and basis differentials. Moreover, Enbridge has a variety of demand- and supply-side resources available. Demand-side resources, such as energy efficiency and demand response, reduce customer demand and thus the Company's and customers' exposure to volatile natural gas prices. To the best of CEG's knowledge, the Company also has the ability to use physical and financial hedges.
(b) CEG is aware and recognizes that storage is a type of physical hedge that can mitigate the Company's exposure to volatile natural gas prices.
(c) CEG is not able to comment on the current state of deregulation of the natural gas market in Ontario. CEG does note, however, whether a customer is "captive" to the natural gas commodity charges of Enbridge is not determinative of the exploration of whether gas supply risks should be more appropriately balanced between the utility and customers and whether the entity that is best positioned to mitigate the risks, i.e., the utility, should be incented to do so.

M2.EGI-23

Reference: Exhibit M2

Question:

(a) If Enbridge Gas assumes risks related to gas price volatility, would it be appropriate to increase Enbridge Gas's allowed ROE to compensate it for the increased risk exposure? Why or why not?

Response:

The appropriate return on equity is dependent on a variety of factors including the state of the economy, comparable returns of other investments of similar risk, the utility's financial integrity, the utility's ability to attract credit and capital, amongst other considerations. CEG recognizes that, all else equal, a utility that shares in gas-price related risk with its customers has more risk than a utility that does not share that risk. The level of risk the utility is exposed to depends on the mechanism, the utility, its market, the situation of comparable utilities, and the specific facts of a proceeding. CEG recommends OEB take a holistic assessment of Enbridge's situation when it sets the return on equity.

M2.EGI-24

Question:

(a) Please provide a list of all proceedings where Matthew McDonnell and Brad Cebulko have been qualified as experts in IRP incentives. Please provide links to that expert evidence.

Response:

See M2.EGI-1.

M2.EGI-25

Questions:

(a) Please provide a list of proceedings where a mechanism similar to CEG's proposed IRPA shared savings mechanism was proposed and approved by an energy regulator in Canada or the United States. Please summarize the request and approval in each such case and provide a link to the regulator's decision and key evidence.
(b) Please provide a list of proceedings where a mechanism similar to CEG's proposed IRPA shared savings mechanism was proposed and not approved. Please summarize the request and decision in each case and provide a link to the regulator's decision and key evidence.

Response:

This request as unreasonably burdensome as it would require a review of all gas regulatory proceedings in all jurisdictions across North America to determine whether similar mechanisms were proposed and what the outcome was in each case.

However in response, New York has incorporated a shared savings mechanism to incentivize non-pipeline alternatives, allowing utilities to earn revenues of up to 30% of the project's net benefits through an incentive mechanism.[8] CEG is unaware of any proceedings in which a IRPA shared savings mechanism was proposed and not approved.

[8] Strategen Consulting. Non-Pipeline Alternatives: A Regulatory Framework and a Case Study of Colorado – Leading Practices in the Screening and Evaluation of NPAs. October 2023. Available at: https://eta-publications.lbl.gov/sites/default/files/non-pipeline_alternatives_to_natural_gas_utility_infrastructure_2_final.pdf. P. 37.

M2.EP-1

Reference: OEB Rules of Practice and Procedure

Preamble: Quote from the OEB Rules of Practice and Procedure:

13A. Expert Evidence

13A.01 Where a party intends to engage one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise, Rule 13 applies to that evidence.

13A.02 An expert shall assist the OEB impartially by giving evidence that is fair and objective. 13A.03 An expert's written evidence shall, at a minimum, include the following:

(a) the expert's name, business name and address, and general area of expertise;

(b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;

(d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence; and

(f) an acknowledgement of the expert's duty to the OEB in Form A to these Rules, signed by the expert.

Question:

(a) Please explain how Exhibit M2 adheres to the rules for Expert Evidence quoted in the Preamble.

Response:

The requirements of the rule are contained in the CEG report, the evidence proposal letter dated July 11, 2024, and the acknowledgement of expert's duty form.

M2.EP-2

Reference: Exhibit M2, Page 4

Preamble: "Market, technology, and policy changes have made it clear that demand for natural gas can no longer be expected to continue rising. The Canada Energy Regulator forecasts that Ontario's natural gas demand will annually decline by 1.07% from 2023 to 2030 in a "Current Measures" scenario where Canada takes limited action to reduce its greenhouse gas (GHG) emissions."

Questions:

(a) Considering that 2023 is over, what was Ontario's natural gas demand in 2023, and did it decline from 2022?
(b) What is the co-authors' forecast of Ontario natural gas demand for 2024, and is it different than the forecast of Enbridge Gas in the evidence?

Responses:

(a) CEG does not have data on gas demand outside of what is publicly available online or in the Company's regulatory filings.
(b) CEG did not and does not forecast natural gas demand for Enbridge Gas. CEG referenced the Canada Energy Regulator's forecast for Ontario. CEG notes that in Enbridge Gas' 2023 Annual Gas Supply Plan Update in EB-2023-0072, the Company writes that "As global climate policy continues to evolve, many demand forecast scenarios are showing a long-term reduction in natural gas consumption."[9]

[9] Enbridge Gas, "2023 Annual Gas Supply Plan Update," EB-2023-0072, at page 10.

M2.EP-3

Reference: Exhibit M2, Page 4

Preamble: "There is reason to believe, however, that current long-term projections overestimate gas demand from residential and commercial customers and possibly industrial customers as well, as efficient electric space and water heating technologies such as heat pumps become more widespread."

Questions:

(a) What was the population growth rate in Ontario in 2023?
(b) Does gas demand correlate with population growth?
(c) Do the co-authors have any evidence from recent OEB rate applications by electricity distributors in Ontario that there is significant increase in customers switching from gas space and water heating to electric space and water heating?

Responses:

(a) This is not relevant. Furthermore, CEG does not have access to data beyond what is available publicly.
(b) Gas demand is dependent upon a number of factors including economic conditions, energy and industry market conditions, population growth or decreases, public policies, and customer preferences. CEG agrees that historically gas demand has correlated with population growth. That correlation may or may not continue into the future.
(c) CEG's identified statement in the preamble references long-term gas demand from customers and changes in end-use appliance technology and costs. Indeed, several prominent studies, including studies from natural gas utilities, forecast declines in demand for natural gas. Below is an example of two recent studies that forecast long-term declines in demand for natural gas:

- Brattle: The Future of Gas Utilities Series, Transitioning Gas Utilities to a Decarbonized Future. Part 1 of 3. August 2021. The Brattle study concluded:
    - "Traditional gas utility business models face increasing risks as more states and locales challenge the long-run role natural gas could play in meeting climate and energy policy goals."
    - "Heating electrification is outpacing gas growth in some parts of the country. At the current pace, the number of homes with electric space heating could surpass homes with gas space heating by 2032."
    - "Up to 60% of New York's gas heating sector may be electrified by 2040."
    - That gas utilities face a potential "Death Spiral" and "Up to $150–180 billion of gas distribution assets could be under recovered as a result of the [natural gas] transition."
- EPRI: "Electrification Scenarios for Ameren Illinois' Energy Future" PIO Exhibit 4.3 Illinois Commerce Commission Docket NO.s 23-0068 and 23-0069. Available at: https://icc.illinois.gov/downloads/public/edocket/593256.PDF. The EPRI study

> concluded that "Efficient electrification is observed across all scenarios with electricity constituting 27-40% of total final energy by 2050."

Furthermore, in 2023, prior to the tax credits and rebates for heat pumps in the Inflation Reduction Act, electric heat pump sales in the United States outsold gas furnaces for the second year in a row.[10]

[10] https://www.canarymedia.com/articles/heat-pumps/heat-pumps-outsold-gas-furnaces-again-last-year-and-the-gap-is-growing

M2.EP-4

Reference: Exhibit M2, Pages 4 and 5

Preamble: "At Canada's most recent forecasts, heat pump costs will decline between 7%-15% by 2030, and up to 40% by 2050, representing significant potential cost savings for electrification across both net-zero and "status quo" scenarios."

Questions:

(a) Have heat pump costs (excluding rebates) declined in Ontario since 2022?
(b) Please confirm that many older homes in Ontario do not have air ducts and are not well insulated which may make switching from gas boiler or electric baseboard heating to electric heat pump more expensive.

Responses:

(a) CEG does not have data to answer this question and does not have sufficient time to research it. Furthermore, CEG referenced a forecast from 2030 to 2050, which is not equivalent to price changes since 2022.
(b) CEG is not familiar with Ontario-specific housing vintages and styles. Having said that, CEG is aware that many older homes in the United States and Canada do not have air ducts nor sufficient insulation. CEG recognizes the abundant cost, health, and comfort benefits of government and utility programs that maximize building, particularly residential, weatherization. Furthermore, all heating systems are most efficient when paired with a well insulated building. CEG encourages government and utility programs to incentivize building weatherization.

M2.EP-5

Reference: Exhibit M2, Pages 5 and 6

Preamble: "The current trajectory of market transformation trends holds real import for Enbridge Gas and remains starkly at odds with forecasts suggesting increasing customer demand and an ever-expanding distribution network. This long-term decline of Ontario's gas utility customer base is primarily based on three exogenous risks that Enbridge will struggle to forecast, let alone control:

1. The growth of public and market actors mandating the reduction of greenhouse gas (GHG) emissions and fossil fuel use to combat climate change and reduce local health and environmental hazards.

2. The interconnected risks of geopolitical instability, such as the ongoing war in Ukraine, that shock natural gas prices with immediate and long-term impacts.

3. The clean energy transition makes electric water and space heating more cost-effective options relative to natural gas appliances and infrastructure."

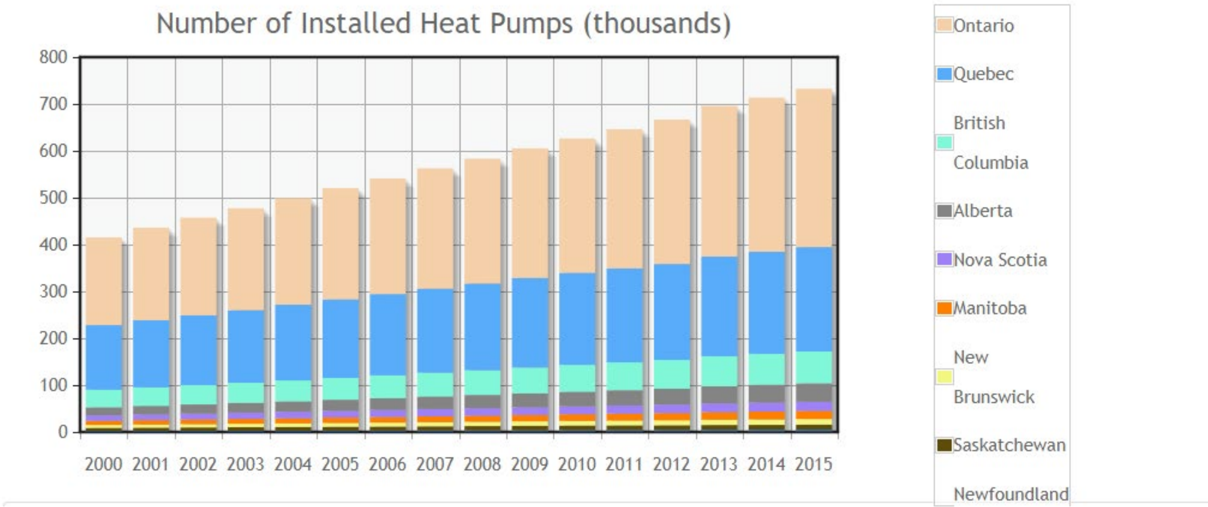
Questions:

(a) Do the co-authors have any numerical evidence of the "trajectory of market transformation trends" in Ontario? If the answer is yes, please file it. If the answer is no, please explain why not.
(b) Considering that most heat pumps available in Ontario are manufactured in China using electricity from coal fired power plants, and that electrification will require large amounts of copper that will need to be mined, smelted, and rolled into wire, all of which will increase GHG emissions, is it possible that switching from gas space and water heating will increase GHG emissions for many years?
(c) What has been the percentage impact of the war in Ukraine on the natural gas that Enbridge Gas is charging its customers?
(d) Over the last 10 years what has been the percentage increase in the price of electricity in Ontario compared to that of natural gas?

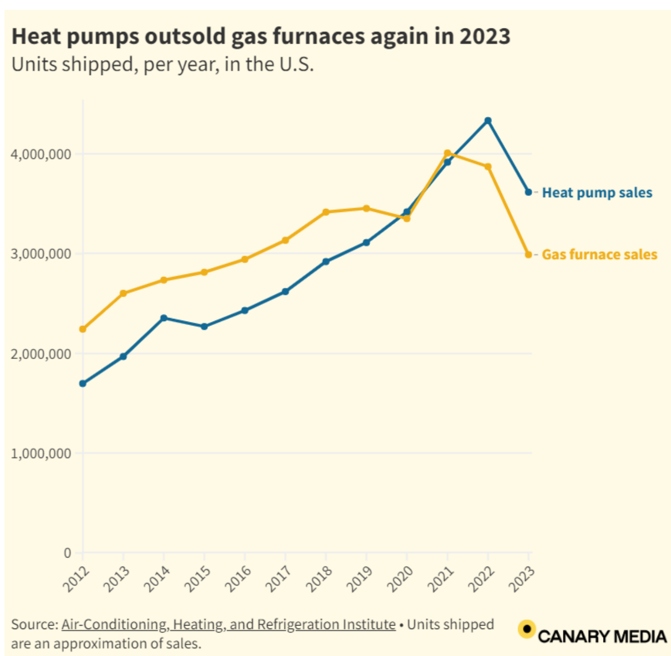
Responses:

(a) Yes. The Canada Energy Regulator reports that the installation of heat pumps has increased significantly over the last decade.[11]

[11] https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2018/market-snapshot-steady-growth-heat-pump-technology.html



In 2023, electric heat pump sales in the United States outsold gas furnaces for the second year in a row.[12]



(b) CEG has not conducted the requested analysis and is unaware of any lifecycle analysis specific to Ontario or Enbridge's service territory. If EP has conducted such an analysis, CEG is interested in seeing the results and supporting analysis. If EP, Enbridge, or another party were to consider conducting such an analysis, CEG offers the following observations:

[12] https://www.canarymedia.com/articles/heat-pumps/heat-pumps-outsold-gas-furnaces-again-last-year-and-the-gap-is-growing

- From a thermodynamic perspective, heat pumps are more efficient than gas furnaces,
- Not all heat pumps are or will be manufactured in China,
- China's electricity sources are not static, and its electricity generation portfolio is evolving[13] much like the rest of the world,
- There is embedded carbon in the manufacturing of gas furnaces and air conditioners that need to be accounted for,
- There is embedded carbon associated with the materials necessary to expand the gas delivery system,
- The greenhouse gas accounting would need to recognize upstream methane leakage from the production, gathering, and transmission of natural gas.

(c) It is difficult to extract a single factor's impact on the price of a global commodity like natural gas. However, there are abundant industry reports, including from Enbridge, that identified a link between natural gas prices and Russia's invasion of Ukraine. For example, in Enbridge's 2023 Gas Supply Plan Update EB-2023-0072, the Company writes, "Through 2022, the natural gas market experienced high prices and volatility due to economies reemerging from the global pandemic, low storage inventory levels, and increased exports of LNG driven largely by global demand increases resulting from the Russia/Ukraine conflict and associated embargoes on Russian natural gas."[14]

Other examples include:

a. Savcenko, K. "How the Russia-Ukraine war is turning natural gas into the 'new oil' S&P Global. April 12, 2023. https://www.spglobal.com/commodityinsights/en/market-insights/blogs/natural-gas/041223-how-the-russia-ukraine-war-is-turning-natural-gas-into-the-new-oil
b. International Energy Agency "Analysing the impacts of Russia's invasion of Ukraine on energy markets and energy security." https://www.iea.org/topics/russias-war-on-ukraine
c. Evans, P. "From energy to food prices and even inflation, here's how war in Ukraine could impact Canada's economy." CBC News. February 24, 2022. https://www.cbc.ca/news/business/ukraine-economic-impact-1.6362992

(d) This is beyond the scope of CEG's evidence.

[13] https://www.reuters.com/business/energy/chinas-plunging-coal-plant-approvals-signal-energy-policy-pivot-report-says-2024-08-22/

[14] Enbridge Gas, "2023 Annual Gas Supply Plan Update," EB-2023-0072, at page 12.

M2.EP-6

Reference: Exhibit M2, Page 6

Preamble: "This report highlights some specific opportunities to improve the proposed elements of Enbridge Gas's Price Cap Incentive Rate-Setting Mechanism (Issue #2) to better align Enbridge Gas's financial incentives with customers' interests in an era of flat or declining gas sales."

Questions:

(a) What are "customers' interests" that the co-authors are referring to?
(b) Do all customers have identical interests?
(c) When did the era of flat or declining gas sales start for Enbridge Gas?
(d) Please confirm that Enbridge Gas's financial incentives are already aligned with customers' interests but could have better alignment.

Responses:

(a) Customer interest generally means energy service that is affordable, safe, reliable, and meeting public policy objectives.
(b) No. Each customer is unique. Regulators nevertheless regulate in the public interest and the industry recognizes that common interests include affordability, safety, reliability, and public policy objectives.
(c) The CEG evidence does not suggest that Enbridge currently has flat or declining sales.
(d) CEG cannot confirm this assertion. While it is in both Enbridge's and customers' interests for the gas delivery system to be safe and reliable, Enbridge's financial incentives are to continuously grow its plant in service to earn a profit, while customers' interests are to enjoy a safe and reliable system at the lowest cost and lowest risk while meeting all public policy requirements.

M2.EP-7

Reference: Exhibit M2, page 9

Preamble: "By reducing the ROE for gas system expansion, the OEB would facilitate the following effects: better aligning the financial incentives extended to Enbridge Gas and more effectively deploying finite capital resources in a manner consistent with the public interest."

Questions:

(a) What is the "public interest" that the co-authors are referring to.
(b) Who decides what is in public interest?
(c) Does public interest change over time?

Responses:

CEG uses the term consistent with its use by the OEB.[15] Further details are beyond the scope of CEG's evidence and involve legal questions.

[15] https://www.oeb.ca/about-oeb/mission-and-mandate

M2.EP-8

Reference: Exhibit M2, page 10

Preamble: "As the example shows, Enbridge can earn additional income based on its performance, in addition to the near-guaranteed return they receive from operational investments. This dynamic incentivizes Enbridge to invest in operational investments to acquire the higher relative return on those investments, and to make those operations as efficient as possible so that their programmatic benefits – and the rewards from those benefits – are maximized."

Questions:

(a) What example are the co-authors referring to?
(b) What are "operational investments" and do the co-authors have evidence that Enbridge Gas is not making them?
(c) What is the "additional income", and would ratepayers have to pay for it through higher rates?

Responses:

(a) Performance-based incentives are an example of a tool that can provide additional income to make up for a lower ROE on growth assets.
(b) Operational investments refers to non-growth investments, such as the repair of a pipeline rather than its full replacement with new pipe.
(c) The additional income is performance-based incentives, which may not result in higher rates (if they coincide with a lowering of ROE on growth assets), a reduction to capital expenditures, and may lower rates by better aligning Enbridge's financial incentives with its customers.

M2.EP-9

Reference: Exhibit M2, page 11

Preamble: "If the OEB desires a more gradual approach to ROE differentiation, then a system expansion investment ROE that is 1% to 3% lower than Enbridge Gas's overall ROE would be a motivating incentive to discourage further system growth and exacerbate stranded asset risk."

Questions:

(d) Please confirm that Enbridge is not forcing customers to use gas and that system growth by Enbridge Gas is in response to demand by customers for gas service.
(e) Do the co-authors believe that new gas customers who just installed new gas-fired appliances are likely to switch to electric space and water heating?

Responses:

(a) CEG is not aware of any regulation or statute that requires customers to use gas. CEG also notes that most residential customers buy a house built by someone else, such as a home builder, and do not choose their energy source.
(b) The answer depends on the end-use equipment and specific conditions of the customer. CEG notes that the capital costs for converting space or water heating is significantly greater than other residential gas end uses, such as cooking, dryers, and fireplaces. Customers who have only low gas usage homes face a lower barrier to convert to an alternative energy source for their gas end-use appliances.

M2.EP-10

Reference: Exhibit M2, page 12

Preamble: "The primary objective of revenue decoupling is to weaken the link between utility earnings and sales volume. Revenue decoupling is designed to enable greater energy efficiency improvements by reducing the "throughput incentive" – the inherent financial incentive that utilities have to sell more therms of gas."

Questions:

(a) Are the co-authors aware that Canada uses the Metric system, and that "therm" is not a Metric unit?
(b) When the co-authors refer to "revenue decoupling" are they referring to the separation of fixed and variable costs in rates charged to customers?
(c) Considering that Enbridge Gas has specific rates for applicable to each customer class, and that the recovery of fixed and volumetric costs is not the same for each rate, which rates do the co-authors believe should be decoupled?

Responses:

(a) Yes. Our understanding is that cubic metres is standard measurement unit in Canada. We also note that, at times, Enbridge Gas uses non-metric terms such as cubic feet[16] or MMBtu[17] on its websites and in its Gas Supply Plan. For reference, one therm equals 100 cubic feet or approximately 2.83 cubic metres.[18]
(b) No.
(c) CEG does not understand the question as posed. Revenue decoupling refers to various alternative regulatory mechanisms that address the throughput incentive, in which the link between a utility's unit sales of gas is loosened or "decoupled" from the utility's collection of target revenues.

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[16] https://www.enbridge.com/about-us/gas-distribution-and-storage#:~:text=In%20September%202023%2C%20Enbridge%20Inc,Wyoming%2C%20Idaho%20and%20North%20Carolina.
[17] Enbridge Gas 2023 Annual Gas Supply Plan Update EB-2023-0072.
[18] Canada Energy Regulator, Energy Conversion Tables: https://apps.cer-rec.gc.ca/Conversion/conversion-tables.aspx?=undefined&wbdisable=true

M2.EP-11

Reference: Exhibit M2, page 11

Preamble: "Revenue decoupling is a tool that addresses the throughput incentive. When variable rates are used to recover costs that are fixed in the short term, the utility can increase its revenues by selling more energy without a corresponding increase in its costs. This creates a powerful incentive to grow sales and oppose measures that reduce energy usage. However, revising the rate structure to collect a greater share of revenues via fixed rates is not an appropriate solution.

A high fixed charge approach to addressing the throughput incentive would undermine customers' incentive to conserve energy and impose greater costs on low-usage (and often low- income) customers."

Question:

(a) It is not clear from the quoted paragraph what the co-authors are recommending. Are the co-authors recommending that less fixed costs should be recovered through the fixed monthly charge and more fixed cost should be recovered through the volumetric charge than is now the case? If the answer is yes, please explain why that is de-coupling. If the answer is no, please explain in detail what the co-authors are recommending.

Response:

No. Revenue decoupling can be achieved through a variety of regulatory mechanisms. CEG recommends that a mechanism be adopted to achieve revenue decoupling with respect to customer counts.

M2.EP-12

Reference: Exhibit M2, page 13

Preamble: "Under revenue decoupling, most, if not all, variations between a utility's expected revenue and actual revenue are "trued up" annually. If the utility sells less gas than expected, rates will increase the following year to make up for the shortfall, and vice versa if it sells more gas than expected.

A Well-Designed Partial Revenue Decoupling Mechanism Should Leave the Utility Indifferent to Customer Additions or Reductions in the Near-Term."

Questions:

(a) What is partial revenue decoupling and how is it different from revenue decoupling.
(b) Please describe in detail the mechanics of partial revenue decoupling.
(c) Are the co-authors recommending revenue decoupling or partial revenue decoupling?

Responses:

(a) Partial decoupling insulates only a portion of the utility's revenue collections from deviations of actual from expected sales.
(b) Under partial decoupling, any variation in sales would result in a partial true-up of utility revenues (e.g., 50%, or 90%, of the revenue shortfall is recovered).
(c) CEG is recommending partial revenue decoupling insofar as its recommendation would insulate only a portion of the utility's revenue collections from deviations of actual from expected sales. Consistent with past OEB guidance on the matter, CEG's proposed partial revenue decoupling mechanism would not insulate Enbridge from weather-related deviations of actual from expected sales.

M2.EP-13

Reference: Exhibit M2, pages 13 and 14

Preamble: "In lieu of an average use variance account, the OEB should consider an alternative approach – revenue per customer class. Like revenue per customer, revenue per customer class determines the appropriate revenue to be collected regardless of the level of demand from customers. Revenue per customer class, on the other hand, is indifferent to the number of customers on the system or to average customer use."

Question:

(a) Please explain in detail the mechanics of revenue per customer class and how it is different from the current cost allocation method used by Enbridge Gas.

Response:

Revenue per customer class, as referenced above, refers to a specific type of revenue decoupling mechanism design and not to a cost allocation method.

M2.EP-14

Reference: Exhibit M2, page 14

Preamble: "To address the OEB's expectation of declining sales from small-volume customers, the OEB should explore a harmonized revenue balancing account that allows for truing up collected revenues against allowed revenues in a manner that is not tied to customer counts or customer average use."

Question:

(a) Please explain in detail the mechanics of a harmonized revenue balancing account.

Response:

This question is overly burdensome and beyond the scope of CEG's evidence. The "harmonized revenue balancing account" refers to the Board's order for Enbridge Gas to establish a harmonized average use variance account in its Phase 1 Decision.[19]

[19] Ontario Energy Board. Enbridge Gas Application for 2024 Rate – Phase 1 Decision and Order. EB-2022-0200. P. 123.

M2.EP-15

Reference: Exhibit M2, page 16 and 17

Preamble: "This bias can be eliminated or reduced by allowing Enbridge to earn a margin on CIACs in certain circumstances. In particular, Enbridge should be eligible to earn a margin on CIACs only if the 40-year horizon is lowered or if Enbridge applies a lower horizon for a customer-specific reason. This would reduce the incentive for Enbridge to oppose a lowering the horizon by counterbalancing a reduction in rate-based connection costs with an additional return derived from the CIAC margin.

This would also increase the incentive for Enbridge to be cautious when calculating the appropriate CIAC for certain risky connection requests. It would also address a potential argument that it is unfair to Enbridge to require it to undertake a large amount of work without any return if connections are increasingly funded through CIACs as opposed to rates."

Questions:

(a) Please confirm that CIACs stands for contributions in aid of construction from new customers to the utility to make an unfeasible project feasible in order to minimize or eliminate cross-subsidies from existing customers.
(b) Please confirm that if the 40-year horizon is lowered, projects would be less feasible and CIAC's would be higher.
(c) Would it be fair for Enbridge shareholders to earn a return on investments that they did not make but were paid for by new customers through CIACs?

Responses:
(a) CEG confirms that CIAC stands for contribution in aid of construction.
(b) CEG agrees that a shorter than 40-year revenue horizon may impact specific project economics and may result in the need for higher CIAC than under a 40-year revenue horizon approach. That said, this would be determined on a project-by-project basis and is the product of various factors.
(c) CEG is not clear what is meant by "fair" in this context. Notwithstanding this ambiguity, CEG observes that it would not be unreasonable for Enbridge to earn a margin on CIACs. There are may instances in which a utility earns a return outside of an authorized rate of return on a capital expenditure, including earnings opportunities or an ROE-adder from achieving certain performance-based incentive mechanisms (PIMs). In addition, there is precedent for an electric utility to earn a margin on operating expenses, such as third-party-hosted cloud computing services, when the treatment thereof helps to levelized the treatment and encourage efficient investment.

    Here, the primary intent is to levelize the treatment of CIAC with the rate basing of customer connection costs in such a manner that reduces any preference, even if unintentional and indirect, for characterizing customer connection costs as rate base when there is an opportunity to more accurately characterize certain customer connection project costs as CIAC.

M2.EP-16

Reference: Exhibit M2, page 19

Preamble: "The OEB should consider revising the QRAM to share gas supply-cost risk more fairly between Enbridge Gas and its customers."

Questions:

(a) Do the co-authors know when the QRAM mechanism was first approved by the OEB and the mechanism that was in place prior to its approval.
(b) Are the co-authors aware of the problems with gas supply hedging and risk sharing that existed before QRAM was adopted by the OEB.
(c) Would the co-authors support a higher equity thickness for Enbridge Gas to compensate it for taking greater commodity risk?

Responses:

(a) CEG is not aware of when the QRAM was first approved by the OEB nor the mechanism in place before its approval.
(b) CEG is not aware of "the problems" with gas supply hedging and risk sharing that existed prior to the adoption of the QRAM by the OEB. CEG maintains that the OEB should examine whether, within the context of an ongoing energy transition, customers would be better served if the Company had some exposure or "skin in the game" regarding the price volatility and other risks associated with gas supply costs. Risks for which customers are poorly positioned to address and mitigate.
(c) CEG takes no position on the appropriate equity thickness for Enbridge. CEG does observe, however, that the appropriate equity thickness for Enbridge needs to be evaluated within the totality of circumstances facing Enbridge and its overarching risk profile, among numerous other factors. While Enbridge may be exposed to greater commodity risk through a gas supply-cost sharing mechanism, such risk could be offset by reducing utility risk in different aspects of its Price Cap Incentive Rate-Setting Mechanism.

M2-SEC-1

Reference: Exhibit M2, p. 3

Question:

(a) For each of the report's authors, please provide a list of all expert evidence that has been authored filed in a regulatory proceeding regarding incentive ratemaking, regulatory frameworks, energy transition or other areas discussed in its report. Please provide a link, or copy of the listed expert evidence, if a link is unavailable.

Response:

Please see the co-authors resumes.

M2-SEC-2

Reference: Exhibit M2, pp. 2-3

Question:

(a) For each proposed recommendation, please provide CEG's view on, if implemented, would they increase or decrease Enbridge's business or financial risk?

Response:

Recommendation 2 (revenue decoupling) would decrease risk whereas recommendation 5 (share gas supply risk) would increase risk. For other recommendations, a properly nuanced answer would require additional analysis and, in some cases, Enbridge-specific data that we do not have access to. CEG observes that a regulator should view a utility's risk profile within its regulatory framework in a comprehensive manner, rather than viewing individual mechanisms in isolation.

M2-SEC-3

Reference: Exhibit M2, pp. 10-11

Questions:

With respect to CEG's proposed differentiated ROE proposal:

(a) Please explain how CEG's proposal works in the context of Enbridge's proposal for a Price Cap IR mechanism between 2025-2028, where except for the use of ICM mechanism and various DVAs, the rate-setting mechanism decouples costs from rates.
(b) Does CEG propose that the differentiated ROE be applied and adjust rates between 2025 and 2028, or that upon rebasing in 2029 the undepreciated capital costs added to rate base attract differentiated ROEs?
(c) How would CEG define "growth capital" for the purposes of this mechanism? Please make specific reference, if possible, to Enbridge's existing capital expenditure and asset categories.

Responses:

(a) This question is unclear.
(b) CEG proposes that the differentiated ROE be applied to the rate period between 2025 and 2028. That said, if the OEB were to determine that the application of differentiated ROE was infeasible for the period 2025-2028, then CEG would, in the alternative, propose that differentiated ROEs be applied upon rebasing in 2029, as deemed appropriate by the OEB.
(c) Growth-related capital includes individual projects and sets of inter-related facilities needed to maintain system reliability and meet a specified capacity expansion need, including for new customers or facilities that are not otherwise new business projects or for reliability and growth related to existing customers.

M2-SEC-4

Reference: Exhibit M2, p.14

Question:

(a) Please explain what CEG means when it says "the OEB should explore a harmonized revenue balancing account that allows for truing up collected revenues against allowed revenues in a manner that is not tied to customer counts or customer average use." [emphasis added]. Is CEG recommending that the OEB undertake further study or consideration of such an approach, or implement it for Enbridge's 2025-2028 IRM term?

Response:

CEG recommends that modifications to the variance account also include more material changes to the variance account for application in Enbridge's 2025-2028 IRM term. CEG understands that changes to the prior variance account may be examined further in Phase 3 of this proceeding. CEG proposes that such an evaluation also consider more significant changes to the current variance account approach as reflected in CEG's Exhibit M2. To the extent that the OEB determines such changes are not warranted or desirable for Enbridge's 2025-2028 IRM term, CEG recommends, in the alternative, that the OEB undertake further investigation in advance of rebasing in 2029.

M2-SEC-5

Reference: Exhibit M2, pp. 14-15

Questions:

With respect to CEG's recommendations regarding an Efficiency Carryover Mechanism (ECM):

(a) Is CEG's recommendation based on Enbridge specific evidence regarding the need for an additional mechanism to incent efficiency? If so, please provide details.
(b) [EB-2012-0459, Decision with Reasons, July 17, 2024, p.15-18] In EB-2012-0459, the OEB rejected a proposal by one of Enbridge's predecessor utility's (Enbridge Gas Distribution) for an ECM (the Sustainable Efficiency Incentive Mechanism). Please explain how CEG's recommendation addresses the OEB's concerns.
(c) [AUC Decision 27388-D01-2023, October 4, 2023, p.95-98] As part of the Alberta Utilities Commission's establishment of both electricity and natural gas utilities 2024-2028 Performance-Based Regulation (PBR) Plan, it discontinued the ECM that had been part of the previous PBR Plan. Please explain how CEG's recommendation addresses concerns that the AUC had with its previously approved ECM.

Responses:

(a) CEG highlighted ECMs as potentially valuable tool for encouraging companies to pursue efficiency gains in every year of an IRM and when structured in a manner that differentiates between an Opex ECM and a Capex ECM, could facilitate more equal treatment between the two expense categories. ECMs are complex, can be difficult to design, and can be configured in various ways.
(b) CEG does not propose a specific and detailed ECM design and therefore cannot articulate how a hypothetical ECM design would compare to the Sustainable Efficiency Incentive Mechanism (SEIM) that it has not studied in detail and was proposed more than a decade ago. CEG does note that the OEB saw merit in a mechanism that serves to incent long-term sustainable productivity improvements and encouraged Enbridge to develop a revised proposal to bring forward for consideration.[20]
(c) The Alberta Utilities Commission (AUC) acknowledged that a utility's incentive to find efficiencies weakens as the end of a PBR term approaches because there is less time remaining to benefit from any efficiency gains before authorized revenues are reset to match costs. Ultimately, the AUC was not persuaded that the ROE-based ECM, included in the first two PBR plan periods, achieved its intended purpose of addressing the weakening of incentives towards the end of the PBR term. The AUC left open the possibility to consider alternative remedies to enhance efficiencies at the end of the plan term, including alternative forms of ECM. Here, CEG would not be advocating for an ROE-based ECM and encourages examination of both an Opex ECM as well as a Capex ECM. Accordingly, while it is not possible to directly address the AUC's concerns with an ROE-based ECM in the context of CEG's proposal, CEG maintains that its proposed approach is consistent with the spirit of the AUC's Findings.

[20] EB-2012-0459, Decision with Reasons, July 17, 2014, p. 16.

M2-SEC-6

References: Exhibit M2, pp.17-20
EB-2006-0034, Decision with Reasons, July 5, 2007, p.37-47
EB-2007-0606, Decision, July 31, 2008, p.11-17

Question:

(a) CEG recommends that QRAM process be modified to expose the company to recovery risk related to gas supply cost volatility. In the past, the OEB directed Enbridge's predecessor utilities (Enbridge Gas Distribution and Union Gas) to discontinue its gas supply Risk Management Program which involved hedging activities, or disallowed recovery of associated costs. Please explain how CEG believes those OEB decisions impact its recommendation.

Response:

(a) CEG did not review nor discuss the issues that were identified with Enbridge's predecessor utilities' that led to the companies discontinuing the gas supply Risk Management Program. However, CEG notes that under its proposals, Enbridge would also be financially exposed to the costs and risks of its strategy. The purpose of CEG's proposal is to align the utility's financial incentives with preferred customer outcomes and shift some risk from customers, who at present carry all of the risk, to the utility.

M2.Staff-1

Reference: Exhibit 10, Tab 1, Schedule 1, pp. 4-5; Exhibit M2, pp. 2-3

Preamble: Enbridge Gas has proposed that rates for 2025 to 2028 be set using a Price Cap Incentive Rate-Setting Mechanism (Price Cap IR), based on the rates set through cost of service for 2024. The Current Energy Group provides an overview of its recommendations to better align Enbridge Gas's financial incentives with customer interests.

Questions:

(a) If the OEB accepts Enbridge Gas's proposal to use a Price Cap IR approach to set rates for the 2025 to 2028 period, does the Current Energy Group believe that all its recommendations could be incorporated into the proposed Price Cap IR approach? Please identify any recommendations that may not be feasible to implement within a Price Cap IR approach, and any changes that Current Energy Group would propose in order to implement its recommendations within the Price Cap IR approach for the term starting in 2025.

(b) Are there examples of jurisdictions that have implemented one or more of the Current Energy Group's recommendations and could potentially serve as useful models for the OEB to consider? Please identify the specific recommendations that were implemented.

Responses:

(a) Given the design complexities inherent in Efficiency Carryover Mechanisms, CEG's proposal related to implementation of an ECM may be challenging to integrate for the term starting in 2025.

(b) Differentiated ROE – none implemented, but see Hawaii statute authorizing differentiated rate of return for different categories of capital expenditures, including a lower authorized rate of return for fossil fuel-based generation assets.[21] In Colorado, Colorado PUC Staff recently submitted testimony advocating for the implementation of differentiated ROE as applied to gas utility capital expenditures.[22]

Revenue decoupling – see Hawaiian Electric Companies revenue balancing account design[23]

Fuel Cost Sharing Mechanism – see Hawaii and Washington state

[21] HI Rev Stat § 269-6e(4) (2023). Available at: https://law.justia.com/codes/hawaii/title-15/chapter-269/section-269-6/.

[22] Proceeding No. 24AL-0049G, In the Matter of Advice No. 1029-Gas of Public Service Company of Colorado to Revise its Colorado PUC No. 6-Gas Tariff to Increase Jurisdictional Base Rate Revenues, Implement New Base Rates for all Gas Rate Schedules, and Make Other Proposed Tariff Changes Effective February 29, 2024. Answer Testimony of Erin T. O'Neill, July 11, 2024.

[23] Hawaiian Electric. Revenue Balancing Account ("RBA") Provision. October 1, 2023. Available at: https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rates/heco_rates_rba.pdf.

The Hawaii Public Utilities Commission requires utilities to include an Energy Cost Adjustment on customer bills that reflects the total cost of buying energy from independent power producers and the price of fuel.[24]
The Washington Utilities and Transportation Commission requires Puget Sound Energy to implement a risk sharing mechanism that appropriately balances the compliance risk between the Company and its natural gas customers, serving as a price signal for both the utility and its customers to modify their behavior to reduce carbon emissions.[25]

IPRA Shared Savings Mechanism – see New York. New York has incorporated a shared savings mechanism to incentivize non-pipeline alternatives, allowing utilities to earn revenues of up to 30% of the project's net benefits through an incentive mechanism.[26]

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[24] Hawaiian Electric. Energy Cost Filings. Available at: https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/energy-cost-filings.
[25] Washington Utilities and Transportation Commission. Allowing Tariff Revisions to become Effective Subject to Conditions – Puget Sound Energy. Docket No. UG-230470. Order 01. Available at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=60&year=2023&docketNumber=230470. P. 6.
[26] Strategen Consulting. Non-Pipeline Alternatives: A Regulatory Framework and a Case Study of Colorado – Leading Practices in the Screening and Evaluation of NPAs. October 2023. Available at: https://eta-publications.lbl.gov/sites/default/files/non-pipeline_alternatives_to_natural_gas_utility_infrastructure_2_final.pdf. P. 37.

M2.Staff-2

Reference: Exhibit M2, pp, 8-11

Preamble: One approach for rebalancing gas utility incentives is through a differentiated return on equity (ROE), where capital expenditures in growth-related investments earn a lower return than capital expenditures in things like safety and mandatory relocations. The evidence recommends a 1% decrease in the ROE for growth capital as a reasonable start.

Question:

(a) Please confirm that the 1% reduction would apply to the OEB-approved ROE.

Response:

CEG confirms the illustrative 1% reduction would apply to the OEB-approved ROE.

M2.Staff-3

References: Exhibit M2, p.11; Exhibit I.1.17-Staff-10; Exhibit I.1.17-ED-26(a)

Preamble: The Current Energy Group states that "another option to maintain a fair return for the utility and achieve balance with a lower return on growth capital is to allow Enbridge Gas to capitalize certain operating and maintenance expenses related to pipeline repair."

Questions:

(a) Would the Current Energy Group recommend that all of the activities Enbridge Gas identifies as O&M in the referenced interrogatory responses be eligible to be capitalized?
(b) Should the OEB adopt the Current Energy Group's recommendation on this issue, are there any concerns regarding consistency with policy on asset capitalization in the accounting standards Enbridge Gas follows (US GAAP)?

Responses:

(a) CEG is specifically referencing O&M investments related to repairing, rather than replacing, Company-owned pipe.
(b) CEG has not analyzed the extent to which the capitalization of certain O&M investments related to repairing, rather than replacing, Company-owned pipe could raise concerns related to US GAAP accounting standards. Capitalization of certain O&M investments is not a primary or critical feature of CEG's differentiated ROE proposal but is offered as a potential avenue for extending additional earnings opportunities in a manner aligned with the spirit of the differentiated ROE approach.

M2.Staff-4

References: Exhibit 10, Tab 1, Schedule 1, p.14; Exhibit M2, pp.12-13

Preamble: Enbridge Gas's IRM proposal includes Y factors for Lost Revenue Adjustment Mechanism volumes to capture the impact of DSM activities, and a Normalized Average Use Adjustment. The Current Energy Group notes that "under traditional regulation, utilities can retain any additional revenue they receive when their sales exceed the forecast that was used to set their revenue requirement, creating a clear incentive for a gas utility to oppose energy efficiency and DSM initiatives that would result in reduced sales." The Current Energy Group proposes a variance account based on revenue per customer class, as opposed to average use per customer.

Question:

(a) Do the Lost Revenue Adjustment Mechanism and Normalized Average Use Adjustment adequately address the Current Energy Group's concerns regarding disincentives to energy efficiency and DSM, and also any concerns regarding disincentives to partial electrification?; i.e. is it only the revenue risk associated with change in number of customers that the Current Energy Group believes is not addressed by Enbridge Gas's proposed rate-setting approach?

Response:

The Lost Revenue Adjustment Mechanism and Normalized Average Use Adjustment do operate to mitigate traditional regulatory disincentives to energy efficiency and DSM. It is less clear how well these mechanisms will work, in practice, to address disincentives to partial electrification. CEG observes that these mechanisms are less able to address disincentives associated with customers departing the system due to full electrification. So, CEG is concerned with the current mechanisms' ability to address the new challenges and complexities presented by both partial and full electrification, including the revenue risk associated with a decline in the number of customers served.

M2.Staff-5

Reference: Exhibit M2, pp.16-17

Preamble: The evidence states that Enbridge Gas currently has an incentive to include connection costs in rate base instead of having them covered by Contribution in Aid of Construction (CIAC). Enbridge Gas earns a profit on the former, but not the latter. The evidence suggests that the bias can be eliminated or reduced by allowing Enbridge Gas to earn a margin on CIACs in certain circumstances. In particular, Enbridge Gas should be eligible to earn a margin on CIACs only if the 40-year horizon is lowered or if Enbridge Gas applies a lower horizon for a customer-specific reason. This would reduce the incentive for Enbridge Gas to oppose a lowering of the horizon by counterbalancing a reduction in rate-based connection costs with an additional return derived from the CIAC margin.

Questions:

(a) The evidence states, “or if Enbridge applies a lower horizon for a customer- specific reason”. Please explain what is meant by “a customer-specific reason”.
(b) Please confirm that the recommended approach is for Enbridge Gas to earn a return on the CIAC margin although the costs are paid for by the connecting customer. In other words, would Enbridge Gas earn a return on amounts that it has not invested?

Responses:

(a) One potential customer-specific reason could include a customer project that has a known gas demand lifespan of less than 40 years.
(b) CEG confirms that its proposed approach would allow for Enbridge to earn a margin on CIAC even though the amounts are not Company-invested capital. There is precedent in the electric sector for allowing earnings on third-party-owned solutions.

M2.Staff-6

Reference: Exhibit M2, pp. 18-19

Preamble: The evidence notes that Enbridge Gas's gas supply costs are a pass-through and therefore Enbridge Gas has little incentive to manage its gas supply costs carefully. The report further states that regulators often find it difficult to determine whether the utility's gas supply expenditures were, in fact, the best use of ratepayer funds. The report further concludes that Enbridge Gas currently has little or no incentive to reduce or control gas supply costs. A modification to the Quarterly Rate Adjustment Mechanism (QRAM) that exposes Enbridge Gas to some amount of risk related to gas supply cost volatility may well be appropriate and induce the company to take more care in guarding against gas supply cost increases.

Questions:

(a) Please explain why the process of reviewing gas supply costs in the QRAM, assessment of annual gas supply plans and benchmarking natural gas costs against market prices are not sufficient to determine reasonableness of Enbridge Gas's gas supply related costs.

(b) Since gas supply costs are a pass-through and the utility does not earn a return on gas supply costs, why should Enbridge Gas assume the risk for gas supply cost volatility?

(c) Considering that there are several factors that impact the price of natural gas (weather, demand, geopolitical uncertainty, transportation capacity etc.) why is it reasonable for Enbridge Gas to assume risks that are beyond its control?

Responses:

(a) The CEG discussion focused on Enbridge's financial incentives and risks as it relates to the structure of the Company's resource decision-making. During the year, the Company has numerous decision points that influence the cost of gas for customers including when it purchases gas, from whom and where, for how long, if it uses financial hedges, when it pulls from physical storage, and what level of demand-side resources it procures. When costs are passed through to customers on a 1:1 basis, the Company's incentives are to minimize its risk. Through a risk sharing mechanism the OEB can better align the utility's financial interests with its customers interests when it makes these decisions.

(b) As explained in subpart (a), the utility has numerous decision points during the year which has a significant influence on the costs that are passed onto customers. The utility has significantly more control over the costs that customers pay then do customers.

(c) At present, customers carry 100 percent of the risks that are beyond their control. While Enbridge does not control the price of natural gas as a commodity, Enbridge has numerous decision points, as described in subpart (a), that influences the total costs borne by customers.

M2-TFG/MC-1

Reference: Exhibit M2, pp. 9-12

Preamble: Current Energy Group ("CEG") notes that EGI is financially indifferent to capital investments related to system growth versus capital investments focused on safety and mandatory relocations. CEG further notes that capital investments related to system expansion carry far greater risk to customers than do capital expenditures centered on safety.

CEG suggests that a differentiated ROE creates a financial incentive for EGI to manage investments in gas system expansion and focus on higher return investments, lowering the overall stranded asset risk of its capital investment portfolio.

Questions:

(a) Is it your position that all capital investments related to system expansion carry greater risk to customers than do capital expenditures centred on safety? If not, what are the merits (or lack thereof) of a more nuanced analysis that considers the risk arising from the specific investment/expenditure in question?
(b) Do all capital investments related to system expansion give rise to the same extent of stranded asset risk? If not, what are the merits (or lack thereof) of a more nuanced analysis that considers the risk arising from the specific investment in question?
(c) Are there certain examples of capital investments related to system expansion that carry the same or less risk to customers than do capital expenditures centred on safety?
(d) Would it be possible to develop an analysis that divides EGI's capital investments in system expansion into risk categories according to the risk of stranded assets that the investments represent? If so, what would be involved in such an approach?
(e) If such analysis or information contemplated above in d) were available, how (if at all) would it affect your analysis and/or conclusions concerning the appropriate ROE for gas system expansion?
(f) Please comment on how an assessment of stranded asset risk would differ for remote communities in Ontario that may receive access to EGI's system through future gas system expansion. In your response, please provide additional comment on how the Ontario government's public policy goals relating to the expansion of natural gas access, as exemplified in the Natural Gas Expansion Program, can impact an analysis of the degree of risk that any particular capital investment supporting system growth carries the risk of becoming stranded.
(g) Please comment on the importance (or lack thereof) of an analysis of the availability of alternative energy options as part of an assessment of the stranded asset risk for any specific capital investment? In your response, please discuss the considerations that remote communities face, including any challenges in accessing reliable, accessible, and low-emitting energy sources.

(h) How could incentives be calibrated to ensure that any disincentive towards natural gas expansion does not come at the expense of improved energy access for remote communities?
(i) To the extent you have not already addressed the issue in your answers above, please comment on whether expansion projects under the Natural Gas Expansion Program face the same risks of stranded assets as other projects.
(j) How could the Natural Gas Expansion Program be restructured in order to reduce any such risks while continuing to promote enhanced energy opportunities for remote communities in Ontario?

Responses:

(a) Generally speaking, yes, CEG believes that capital expenditure investments related to system growth are riskier than capital expenditure investments related to safety. In its report, CEG wrote that the Canada Energy Regulator forecasts that Ontario's natural gas demand will annually decline by 1.07% from 2023 to 2030 in a "Current Measures" scenario where Canada takes limited action to reduce its greenhouse gas (GHG) emissions In Enbridge Gas' 2023 Annual Gas Supply Plan Update in EB-2023-0072, the Company writes that "As global climate policy continues to evolve, many demand forecast scenarios are showing a long-term reduction in natural gas consumption."[27] If gas demand declines, the benefits of near-term growth-related investments, that are built to meet increasing demand, are less likely to be realized than in a scenario in which demand is growing.
(b) No, not all investments have the same level of risk. If the analysis is determined to be feasible, the benefits of a more nuanced approach would be better granularity of individual projects. However, CEG is uncertain if a more nuanced approach is feasible given that gas utilities typically make hundreds or even thousands of capital expenditure investments of various sizes in a given year and the review and classification of each investment may be burdensome.
(c) One example of a riskier growth-related capital expenditure is an investment related to connecting new buildings that only connect non-space and no-water heating end-use gas appliances. The costs to convert a gas dryer, gas stove, or gas fireplace is significantly less than converting space or water heating gas appliances.
(d) CEG has not seen such an analysis conducted. While it is possible, it may require significant time and resources from interested parties to review the projects to determine if they were classified correctly. To develop this method, the OEB would need to determine the classifications of risk, describe the types of projects that fall under each type of risk level, interested parties would need to review Enbridge's classification of projects in accordance with OEB direction, and disputes would need to be resolved by the OEB.
(e) It is difficult to respond to theoretical concepts. If the OEB took the path described in subpart (d), CEG would take that analysis into consideration when making recommendations.
(f) The assessment of the risk of stranded assets would consider the availability, costs, and benefits of the energy sources available to a community. Regulators must balance

[27] Enbridge Gas, "2023 Annual Gas Supply Plan Update," EB-2023-0072, at page 10.

competing objectives including safety, reliability, affordability, sustainability, and public policy goals, such as the expansion of natural gas to remote communities.

(g) If the OEB or another party decided to conduct an analysis of the risk of a specific asset being stranded., the near-term and long-term availability and costs of various sources of energy should be considered, as well as the public policy goals of the province and Canada.

(h) CEG does not understand the question.

(i) CEG answered the question in previous subparts.

(j) This question is beyond the scope of CEG's engagement.

M2-TFG/MC-2

Reference: Exhibit M2, pp. 16-20

Preamble: CEG notes that EGI currently has an incentive to include connection costs in rate base instead of having them covered by CIACs but that this is contrary to the interests of existing gas customers, who benefit if connection costs are covered by CIACs.

CEG recommends making EGI indifferent between the two connection cost recovery mechanisms.

Question:

(a) How, if at all, should the Board distinguish between different types of system expansion for the purposes of your recommendations concerning CIACs? In your answer, please provide comment on how the Board should consider the interests and circumstances of remote and Indigenous communities as compared with, for example, an expansion driven by industrial/commercial demand.

Response: The underlying risks may be the same or substantially similar, but other policy and equity considerations may necessitate a differentiated approach.

M2-TFG/MC-3

Reference: Exhibit M2, pp. 20-21

Preamble: CEG recommends that the OEB should examine opportunities to level the financial playing field for Integrated Resource Plan Alternative ("**IRPA**") projects – both as against traditional infrastructure investments as well as between EGI-owned projects and third-party owned projects.

CEG further recommends that the OEB should examine opportunities to allow Enbridge Gas to earn a return on third-party owned IRPA project costs.

Question:

(a) Please elaborate on any benefits for remote and/or Indigenous communities that you see as likely to result from your recommendations concerning IRPAs. Among any other views you may have, please include in your response any views you have on how your recommendations would:
  i. support reliable, affordable, and/or low-emitting energy sources for remote and/or Indigenous communities; and
  ii. affect opportunities for First Nation equity participation in energy projects.

Response:

(a) Third-party ownership may include Indigenous and First Nation ownership. The Province and OEB could give preference for Indigenous and First Nation ownership such as through a benefit adder. For example, in In the Pacific Northwest of the United States, utilities add a 10% benefits preference adder for energy efficiency to reflect the Northwest Power Act's identification of energy efficiency as a preference resource. The OEB could take a similar approach and apply a percentage adder for IRPAs that are owned by, or provide direct benefits to Indigenous and First Nation communities.