Joel Denomy
Technical Manager
Strategic Applications – Rate Rebasing

tel 416-495-5499
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8

August 23, 2024

VIA RESS AND EMAIL

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas, or the Company)
EB-2024-0111 - 2024 Rebasing – Enbridge Gas Interrogatories for Intervenor Evidence

In accordance with Procedural Order No. 2 issued by the Ontario Energy Board (OEB) on May 30, 2024, enclosed please find the interrogatories of Enbridge Gas for the following filed evidence:

- Exhibit M1 – ED/GEC Evidence on ETTF, Low Carbon Energy Program, System Pruning/IRP and Residential Heating Fuel Cost Comparison (Energy Futures Group)
- Exhibit M2 – ED Evidence on IRM (Current Energy Group)
- Exhibit M3 – OEB Staff Evidence on IRM (Pacific Economics Group)

Should you have any questions, please let us know.

Sincerely,

Joel Denomy
Technical Manager, Strategic Applications – Rate Rebasing

<u>ETTF</u>

M1.EGI-1

<u>Reference:</u>

Exhibit M1, page 12

<u>Preamble:</u>

Energy Future Group (EFG) states: “While Enbridge has not yet identified the range of technologies whose development it intends to fund in 2025, let alone over the next several years, it appears prepared to potentially fund a wide range of technologies. That could result in spreading funds across too many projects to have a material impact on the development of any of them.”

<u>Question(s):</u>

Please clarify what “material impact” means for a technology that is still at the development stage. What are the criteria and threshold to determine whether it is a material impact or not?

M1.EGI-2

<u>Reference:</u>

Exhibit M1, page 12

<u>Preamble:</u>

EFG states: “Put another way, the marginal contribution that Enbridge could make to their market development is likely to be negligible if the Company’s funds are not concentrated on field tests, demonstration projects and/or pilot programs in Ontario. In our experience, such field tests or demonstration projects often cost millions of dollars when undertaken at a scale necessary to produce enough data to evaluate and inform other potential future investments in the province.”

<u>Question(s):</u>

Please provide a list of field tests and demonstration projects that you have experience with similar in size to those proposed in ETTF. Please include detailed description of such projects including costs.

M1.EGI-3

Reference:

Exhibit M1, page 12

Preamble:

EFG states: “An alternative to completely rejecting the fund would be to require that it be targeted solely to one major energy transition need that is universally recognized by the industry – not just by Enbridge – as a safe bet.”

Question(s):

Please indicate examples of a major energy transition need that is universally recognized by the industry that EFG would support as being a funding recipient from the ETTF? Please provide references to substantiate the examples of universally recognized needs.

M1.EGI-4

Reference:

Exhibit M1, page 13

Preamble:

EFG states: “Finally, we recommend that the Board create a stakeholder advisory committee that would be expected to work with Enbridge on both the development of a scoring rubric, the actual scoring of different options and ultimately the selection of project funding priorities. Under its current proposal, the Company will ultimately make decisions on which technologies it will support with ETTF funds without any structured stakeholder input. Given the concerns noted above, creating a structured process for stakeholder input is important to ensuring effective ETTF spending.”

Question(s):

a) Please elaborate on the proposed stakeholder advisory committee structure, for example, size, composition, frequency of meeting, level of involvement etc. What would be a reasonable amount of time for the committee members to accomplish the tasks proposed?

b) Considering that the number of projects/ideas to be reviewed under the ETTF could be more than one hundred every year, what would be a reasonable range of expenditure for the proposed Stakeholder Advisory Committee for scoring of different options and ultimately the selection of project funding priorities?

c) Please provide examples of stakeholder advisory committee from other jurisdictions and its involvement to manage a similar size technology innovation fund, if any.

d) Please clarify what would be considered as “structured stakeholder input”.

e) Please clarify what would be considered to be “effective ETTF spending”. What are the criteria to assess the effectiveness?

M1.EGI-5

Reference:

Exhibit M1, page 8

Preamble:

EFG states: “While there are some potential electrification options for some lower-heat industrial process loads...”

Question(s):

a) Please define lower-heat industrial process loads.

b) Is industrial high pressure, high temperature steam considered high heat industrial process loads?

M1.EGI-6

Reference:

Exhibit M1, page 9, footnote 9

Preamble:

“For example, the 2020 Canadian Climate Institute study (p. 59)...”

Question(s):

Please provide a full copy of the referenced study in footnote 9.

M1.EGI-7

Reference:

Exhibit M1, page 10

Preamble:

EFG states: "…a 30% hydrogen blend would be providing only about 1% to 3% of the total required GHG emission reduction."

Question(s):

Please clarify footnote 13 and how the 1 percent to 3 percent of the total required GHG emission reduction is calculated, including any assumptions on which these calculations were based.

Low Carbon

M1.EGI-8

Reference:

Exhibit M1, page 20

Preamble:

EFG states: "Even at existing and potential new RNG production sites, the on-site use of biogas for heat or power production may be a more economically attractive and valuable emission reduction resource than injection into the gas distribution system."

Question(s):

Provide the cost of reducing emissions in $/tonne of CO_2e emissions for on-site use of biogas to produce heat or power in Ontario. Please show the calculations and include source references. Enbridge Gas suggests the following assumptions be used; however, where EFG uses different assumptions, please provide the assumption used and the rationale.

- Use the assumptions and calculations provided at Phase 2 Exhibit I.4.2-ED-41 part a), Table 1
- Table 2 of the Ontario Energy Board Regulated Price Plan Price Report for November 1, 2023 to October 31, 2024, which shows 26.8 cents/kWh ($74/GJ) for bioenergy power (which includes biogas/landfill gas power).

M1.EGI-9

Reference:

Exhibit M1, page 30

Preamble:

EFG states: “The Company’s assumption in the LCEP application that the carbon intensity of RNG can be assumed to be zero is not supported by these tables.”

Question(s):

a) Please provide the specific text and reference from Phase 2 Exhibit 4, Tab 2, Schedule 7, where Enbridge Gas has indicated that the carbon intensity of RNG is zero.

b) Please confirm that carbon intensities (i.e., lifecycle GHG emissions) are different from emission factors used to calculate facility emissions (i.e., direct end-use emissions) and are not interchangeable terms.

c) Please confirm that carbon intensity is not used to calculate facility emissions in Version 7.0 of Canada’s Greenhouse Gas Quantification Requirements for Canada’s Greenhouse Gas Reporting Program.

d) Please confirm that carbon intensity is not used to calculate facility emissions in Ontario Regulation 390/18: Greenhouse Gas Emissions: Quantification, Reporting, and Verification, or the March 2024 Version of the Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions under Ontario’s Emissions Reporting Program.

M1.EGI-10

Reference:

Exhibit M1, page 20

National Renewable Energy Laboratory. (2021 September). Life Cycle Greenhouse Gas Emissions from Electricity Generation: Update, Table 1.
https://www.nrel.gov/docs/fy21osti/80580.pdf

Ontario Energy Board. (2023 October 19). Regulated Price Plan Price Report November 1, 2023 to October 31, 2024, Table 2.
https://www.oeb.ca/sites/default/files/rpp-price-report-20231019.pdf

Preamble:

Table 1
Total Life Cycle Greenhouse Gas Emissions for Electricity Generation Technologies and Percentage of Electricity Supply in Ontario

Electricity Generation Technology	Median Value Total Life Cycle Greenhouse Gas Emissions (gCO2e/kwh) (1)	% of Electricity Supply in Ontario (2)
Photovoltaic	43	2%
Hydropower	21	26%
Wind	13	9%
Nuclear	13	50%

Notes:
(1) Values have been reproduced from selected electricity generation technologies provided from the National Renewable Energy Laboratory report, Life Cycle Greenhouse Gas Emissions from Electricity Generation: Update, Table 1
(2) Values have been reproduced from selected electricity generation technologies provided at the Ontario Energy Board Regulated Price Plan Price Report, Table 2

EFG states: "…the LCEP should be required to account for different carbon intensities in their reported emission reductions and prioritize newly developed, in region, supplies with negative or zero CI values."

Question(s):

a) Please confirm that the median lifecycle greenhouse gas (GHG) emission values for photovoltaic, hydropower, wind, and nuclear power as provided by the National Renewable Energy Laboratory September 2021 Update on Life Cycle Greenhouse Gas Emissions from Electricity Generation in Table 1 are not zero or negative, and that the majority of electricity supply in Ontario does not have zero or negative lifecycle GHG emissions.

b) Please confirm that the use of RNG within Ontario's Emissions Performance Standard Program does not include considerations related to age of the RNG production facility or carbon intensity (or lifecycle GHG emissions) of the RNG supplies as per the March 2024 Version of the Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions under Ontario's Emissions Reporting Program, Sections ON22.1 RNG Reporting Requirements and ON23.1 Calculation of RNG CO2 Quantity.

M1.EGI-11

Reference:

Exhibit M1, pages 14 and 16

Preamble:

Exhibit M1, page 14:

EFG states: “As detailed below, we recommend the following:

1. Redirect funds to more cost-effective uses: The OEB should require that the Company reduce the LCEP portfolio targets by a factor of 4, cap the price at $25.58/GJ, and redirect the savings to expanded energy efficiency.”

Exhibit M1, page 16:

EFG states: “We recommend lower targets for the LCEP, and redirecting of the resulting savings towards alternative decarbonization investments such as increased energy efficiency.”

Question(s):

a) Please confirm that the lower targets for the low carbon energy program as proposed in the recommendation will result in lower commodity costs for RNG, not “savings” as suggested at Exhibit M1, pages 14 and 16.

b) Please confirm the recommendation as proposed would require Enbridge Gas to charge sales service customers an amount that is greater than the commodity cost Enbridge Gas would incur on behalf of sales service customers.

M1.EGI-12

Reference:

Exhibit M1, page 18

Preamble:

EFG states: “Particularly in the near-term, during the proposed LCEP time horizon, RNG market development will not be limited by the amount of feedstock resources or by the potential number of sites that could be developed. Instead, the economics and comparative advantages of other competing renewable resources, utility and customer investment opportunities, and existing infrastructure and policy and planning factors are more likely to spur and or limit RNG growth.”

Question(s):

Please confirm that the low carbon energy program will spur RNG growth and that in the near term RNG market development will not be limited by the amount of feedstock resources.

System Pruning and IRP

M1.EGI-13

Reference:

Exhibit M1, page 21

Preamble:

EFG states: "As detailed below, we recommend that the OEB require that Enbridge develop its approach to system pruning in consultation with the IRP Working Group within 6 months and begin implementation on a small pilot within 12 months. This is possible because Enbridge can leverage its existing IRP Framework. Further, if the pilot is relatively small and inexpensive, which may be likely, an application for formal approval would not be necessary or reasonably justified."

Question(s):

Without formal approval from the OEB, what do you see as the proper regulatory oversight and review process for a system pruning IRPA, including the review or approval of the cost implications of potentially electrified solutions?

M1.EGI-14

Reference:

Exhibit M1, page 22

Preamble:

EFG states: "We do not see the need for entirely new processes for many of these issues for system pruning. Put simply, system pruning options can and should largely be considered in much the same way that other IRPA projects are considered.

Similarly, we do not see a need for the Company to have to consult the IESO or local municipalities about such projects. Electrifying a few customers should not affect electric grid loads at a level important to the IESO and local municipalities do not need to be I involved in individual customers' fuel choices."

Question(s):

a) Given the goal that processes for developing system pruning pilots could potentially be replicated and scaled up in the future, please explain what the expected learnings from a pilot would be if it does not include testing the current IRP Framework and processes to identify and evolve where processes (including coordinated energy planning) must be modified for system pruning considerations.

b) Please provide a conceptual example of the size and scope of a system pruning project that would be appropriate for a pilot project?

M1.EGI-15

Reference:

Exhibit M1, pages 22 to 23

Preamble:

EFG states: “It should also be noted that though it is not yet commonplace, several jurisdictions have begun to invest in gas system pruning. For example, as noted in a white paper recently published by National Grid (a large gas utility serving customers in several northeastern states) and the Rocky Mountain Institute (a non-profit advocacy organization promoting clean energy), Pacific Gas and Electric has already completed 85 pruning projects in its California gas service territory.”

Question(s):

a) Please indicate if Pacific Gas and Electric (PG&E) operates as an integrated gas and electric utility.

b) How would PG&E’s approach to system pruning be different from Enbridge Gas’s as a standalone gas utility? In your response, please include challenges that may exist for a standalone gas utility that wouldn’t exist for an integrated gas and electric utility.

c) Please confirm that the full reference as started above includes, “Pacific Gas & Electric (PG&E) has successfully completed 88 targeted electrification projects, including decommissioning 22 miles of transmission pipe and converting 105 customers from gas.”

d) What is the biggest system pruning project that EFG is aware of that has been completed for any North American gas utility, in terms of number of customers converted and value or size of gas system decommissioned?

e) Please confirm that the Targeted Building Electrification and Gas System Decommissioning Pilot Project (for which PG&E is a project partner) as referenced in the white paper published by National Grid and RMI, launched in 2021 with a final report released in June 2024, took three years to develop an analytical framework for targeted electrification and strategic gas decommissioning and did not include implementation of gas decommissioning projects during this three-year period.

M1.EGI-16

Reference:

Exhibit M1, page 23

Preamble:

EFG states: “Finally, we recommend that Enbridge consider strategies for addressing situations where most customers are prepared to fully electrify but a very small number or portion are not. When that occurs in a situation in which getting all customers to disconnect from the gas distribution system would provide significant economic benefits to gas ratepayers as a whole, it may be appropriate to consider options other than just incentives. One option might be different gas rates for such “hold outs” that would fairly reflect the cost they are imposing on the system.”

Question(s):

a) Please provide a list of other jurisdictions in North America where a higher rate is charged for customers that “holdout” on system pruning projects.

b) Please provide EFG’s view on how the proposal of different gas rates for “hold outs” could be workable or reconcilable with the principle of non-discriminatory and postage-stamp rate-making.

c) How have other jurisdictions dealt with this issue (has this included policy or legislative changes)?

M1.EGI-17

Reference:

Exhibit M1, page 23

Preamble:

EFG states: “We also recommend that the Board require Enbridge to identify, develop and implement an initial system pruning project within 12 months.”

Question(s):

Please confirm the steps that EFG suggests implementation within 12 months should include? For example, would this include identifying suitable pipeline segments for pruning, completing technical and economic evaluation, achieving consensus from all customers attached to the identified segment to fully electrify, filing an application to the OEB and receiving approval, and completing the necessary work to electrify each customer and decommission the pipeline segment?

Energy Comparison

M1.EGI-18

Reference:

Exhibit M1, page 26, Figure 2

Question(s):

Please provide all assumptions and calculations used in determining $755 annual heating cost for 'Electric Heat Pump' in a live excel file with sources stated.

M1.EGI-19

Reference:

Exhibit M1, pages 26 to 27.

Preamble:

EFG states: "Most notably, we would expect many of homes with electric resistance heat to require the installation of ducts in order to enable the installation of a gas furnace."

The above statement outlines EFG's view on the proportion of homes that have electric baseboards vs electric furnaces for space heating, without any supporting data.

Question(s):

a) Please confirm that it is EFG's position that electric resistance heating in Ontario is synonymous with baseboard heating. If yes, please provide all relevant Canadian sources to support the position. If not, please explain and provide all relevant Canadian sources to support the position.

b) What proportion of homes that currently use electric resistance heating in Ontario have central air conditioning? Please provide all relevant Canadian sources to support the response.

c) Please confirm that adding ccASHP to homes that don’t currently have air conditioning will increase the homes annual electricity consumption, and summer peak demand.

M1.EGI-20

Reference:

Exhibit M1, page 27

Preamble:

EFG states: “[I]t is important to recognize that Ontario’s electric grid is currently summer peaking. Because cold climate heat pumps are typically more efficient at cooling than the air conditioning systems they would displace, they should provide significant near-term benefits to the grid – both in reducing generating capacity needs and in reducing capacity constraints for the portions of the distribution system that are also summer peaking.”

Question(s):

a) Are all homes in Ontario in an area where the electric grid is summer peaking?

b) If the answer to (a) is no, what areas are not summer peaking? What would be the impacts to the grid in those areas if all homes were to convert to electric ccASHP.

Differentiated ROE

M2.EGI-1

Question(s):

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.

M2.EGI-2

Question(s):

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.

M2.EGI-3

Question(s):

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.

M2.EGI-4

Reference:

EB-2024-0063

Question(s):

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.

M2.EGI-5

Question(s):

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

M2.EGI-6

Question(s):

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

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(s):

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

Revenue Decoupling

M2.EGI-8

Question(s):

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.

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.”

Question(s):

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.

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."

Question(s):

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).

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."

Question(s):

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.

Efficiency Carryover Mechanism and Capex Efficiency Sharing

M2.EGI-12

Question(s):

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.

M2.EGI-13

Question(s):

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

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.

Question(s):

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.

Remove Bias Against CIACs

M2.EGI-15

Question(s):

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.

M2.EGI-16

Question(s):

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.

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(s):

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

Share Gas Supply Risk

M2.EGI-18

Question(s):

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.

M2.EGI-19

Question(s):

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.

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(s):

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".

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(s):

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?

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."

Question(s):

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.

M2.EGI-23

Reference:

Exhibit M2

Question(s):

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?

IRPA Shared Savings Mechanism

M2.EGI-24

Question(s):

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.

M2.EGI-25

Question(s):

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.

Statistical Benchmarking

M3.EGI-1

Reference:

Exhibit M3, page 78

Exhibit M3, page 80

Preamble:

Pacific Economics Group (PEG) developed an econometric model that played a critical role in its recommended stretch factor and productivity factor for Enbridge Gas's proposed IRM.

At page 78, PEG states: "We benchmarked the non-fuel O&M expenses, capital cost, and multifactor ("total") cost of EGI using the econometric models detailed in the prior section. In this section we provide some background information about EGI, compare the Company's business conditions to sample norms, and discuss our benchmarking results using productivity indexes and econometric methods."

At page 80, the PEG Report provides the following results of PEG's cost benchmarking model (Actual minus Predicted Costs):

Table 6
Econometric Cost Level Benchmarking Scores

Period	Total Cost	Capital Cost	O&M Cost
2019	25.66%	26.74%	11.70%
2020	26.00%	26.29%	14.66%
2021	21.66%	24.72%	1.24%
2022	22.46%	24.09%	3.33%

Question(s):

a) For each year from 2006 through 2022, please provide the following components of PEG's benchmarking analysis:
    - Enbridge Gas's actual total costs;
    - Enbridge Gas's actual capital costs;
    - Enbridge Gas's actual O&M costs;
    - Enbridge Gas's predicted total costs;
    - The percentage change in Enbridge Gas's predicted total cost, relative to the preceding year;

- The independent variables listed in Exhibit M3, page 73, Table 3, for each sampled U.S. utility, 2006 to 2022;
- Enbridge Gas's predicted capital costs;
- Enbridge Gas's predicted O&M costs;

b) Please confirm that Enbridge Gas's predicted cost in each year depends entirely on the estimated parameter values presented in Exhibit M3, page 73, Table 3 (i.e. there are no coefficient updates to reflect new data) and values of the independent variables for the relevant years.

c) Please confirm that, if requested, PEG will complete further reasonable sensitivity tests and scenario analysis in advance of the Oral Hearing.

M3.EGI-2

Reference:

Exhibit M3, page 85

Question(s):

Please confirm that at page 85 of the PEG report, PEG's recommended stretch factor of 0.45% is explicitly linked to Enbridge Gas's total cost benchmarking results, rather than its capital cost results.

M3.EGI-3

Reference:

Exhibit M3, page 73, Table 3

Exhibit M3, page 75, Table 4

Exhibit M3, page 77, Table 5

Preamble:

PEG provides a partial regression output for the three econometric models it estimated at Tables 3, 4 and 5. Although PEG's work provides parameter estimates and t-statistics on the model's independent variables, it does not provide any evidence on Enbridge Gas's actual cost or predicted cost for any of three PEG models in any of the sample years. Moreover, there is no discussion of any diagnostic tests or sensitivity analyses designed to ensure that the econometric results models are robust and unbiased. Aside from the estimates presented in the aforementioned tables PEG does not present any of the standard statistics that would typically be presented for each of its models. In addition, there is no discussion of any of the standard diagnostic tests that PEG used to determine if its models are robust and satisfy the assumptions required for ordinary least squares regression analysis.

Question(s):

Please reply to the following statements, most of which ask Dr. Lowry to confirm a statement. If a statement is not confirmed, please explain in detail why the statement is incorrect.

a) To provide reliable (i.e. unbiased or consistent) statistical results, a regression model must have independent (i.e. 'exogenous') variables that are not correlated with the error term of the model.

b) If this condition is not satisfied, the regression model has what is known as an instrumental variable problem.

c) Instrumental variable problems can arise for a number of reasons, but in almost all cases, they reflect problems with independent variables used in regression models. For example, independent variables may be measured with error, or they may be correlated with other variables that are measured with error, or they may be correlated with other variables that are themselves correlated with the dependent (endogenous) variables.

d) Any such correlation would lead to biased or inconsistent regression results which would not, in turn, generate reasonable inferences on a utility's cost performance.

e) PEG's regression models treat all outputs, including customer numbers, as exogenous variables.

f) Treating customer numbers as an exogenous variable implies that the number of customers served by a utility is a random, independent variable beyond the control of the utility company.

g) The estimated coefficients (i.e. parameter estimates) for customer numbers and outputs are important, because they factor into the computation and prediction of economies of scale expected for a given utility.

h) Projected economies of scale will in turn factor into a utility company's predicted costs and therefore its cost performance.

i) PEG's benchmarking model approach does not capture or reflect the underlying dynamics of the Union-Enbridge Gas Distribution merger. One reason is that the PEG benchmarking models focus on how a utility's costs compare to the costs, and associated technology, of theoretical production functions. These benchmarking exercises are designed to assess what is known as static productive efficiency, or how efficient a utility is at a given point in time.

j) However, mergers can potentially create efficiencies that go beyond static efficiency gains by altering the technology itself; this is an example of what is known as “dynamic efficiency.”

k) The PEG model is not designed to measure the transformative, technical change associated with dynamic efficiency, or efficiency gains that alter the production function itself, particularly over short periods of time.

l) Instead, PEG’s models measure technical change as a steady, annual process that does not accelerate or decelerate at any point in time. This process applies equally to every sampled company in the utility industry (in this case, the gas distribution industry). In PEG’s current model, at page Exhibit M3, page 73, Table 3, the industry’s rate of technical change is typically measured by the “trend variable,” which has an estimated parameter value of 0.00602, or 0.602 per cent in PEG’s total cost model. PEG’s model therefore assumes that costs in the gas distribution industry increase by 0.62% in each year, for reasons that cannot be explained by PEG’s total cost model.

m) The sample period used to estimate PEG’s econometric model includes the 2020 and 2021 years, when the world was suffering from the Covid pandemic.

  i) Does Dr. Lowry believe the Covid pandemic impacted the performance of essentially every economic sector in the U.S. and Canada in 2020-2021? Please explain.

  ii) Does Dr. Lowry’s econometric model include any variables that reflect the impact of the 2020 to 2021 global pandemic on gas distributors’ cost performance? If so, please identify these variables, their estimated coefficients, and tests of their statistical significance.

  iii) If Dr. Lowry’s econometric model does not measure the impact of the 2020 to 2021 pandemic on Enbridge Gas’s cost performance, would it be reasonable to conclude that the lack of a Covid variable is an example of omitted variable bias? If not, please explain where the impact of Covid in 2020 to 2021 is otherwise measured in the PEG model.

n) In 2022, the Covid pandemic abated somewhat, and worldwide commerce began to recover. Price inflation rose substantially in 2022, and this inflation was exacerbated by international supply chain issues.

  i) Does Dr. Lowry believe the supply chain problems in 2022 could have potentially impacted Enbridge Gas’s utility operations and cost performance? Please explain.

ii) Does Dr. Lowry's model include any variables that reflect the impact of the 2022 supply chain issues on utility operations? If so, please identify these variables, their estimated coefficients, and tests of their statistical significance.

o) At page 80 of the PEG Report, PEG measures Enbridge Gas's cost performance over the 2019, 2020, 2021, and 2022 years. The period used to benchmark Enbridge Gas's cost performance therefore includes the Covid years of 2020 to 2021, and the worldwide surge of inflation and supply chain issues in 2022.

   i) Does Dr. Lowry agree that the 2020 to 2022 years were especially chaotic and uncertain, compared with the preceding 50 years?

   ii) If so, should tests of the statistical significance of PEG's predicted 2019-2022 costs for Enbridge Gas take explicit account of the exceptional uncertainty of the 2020 to 2022 period? Please explain in detail.

   iii) In general, does PEG's econometric model take account of either the impact or uncertainty of 2020 to 2022 Covid-related events?

   iv) If so, please identify precisely where the impact of Covid and supply chain issues are reflected in 1) PEG's estimated parameter values; 2) statistical tests of significance for each parameter estimate; 3) the magnitude of the "confidence intervals" around PEG's predicted costs for Enbridge Gas in 2019 to 2022, which are designed to reflect the uncertainty of the econometric model's predicted costs; and 4) statistical tests of the predicted costs for Enbridge Gas in 2019 to 2022?

p) More formally, does PEG agree that the EGD-Union Gas amalgamation has almost certainly created an instrumental variable problem? Recall that the instrumental variable problem arises whenever there is a correlation between one or more exogenous variables and the error term of the model.

q) Please confirm that, in PEG's model, a utility's measured cost efficiency is estimated within the error term of the model.

r) Please also confirm that 1): a key motivation for the Enbridge Gas-Union Gas merger was to achieve efficiency gains; and 2) Enbridge Gas expected that the merger would generate cost efficiencies. If PEG disagrees with either of these statements, please explain in detail.

s) Please confirm that if any efficiencies were achieved after the amalgamation, they would be reflected in the error term of PEG's econometric model, because that is where PEG measures efficiency gains. If not, please explain in detail.

t) Please confirm that the preceding bullet point implies that if the amalgamation led to any efficiency gains, there would be a positive correlation between the error term of PEG model (because that is where PEG measures efficiency gains) and the number of customers served, which is one of the exogenous, independent cost driver variables in PEG's econometric cost model; if not confirmed, please explain in detail.

u) In the preceding bullet point, this positive correlation between the error term in PEG's model and one or more of PEG's independent variables (i.e. customer numbers) clearly satisfies the definition of an instrumental variable problem. If not, please explain in detail.

v) Please confirm that there is accordingly a high probability that PEG's econometric model has an embedded instrumental variable problem, and it is therefore generating biased (or inconsistent) estimates of Enbridge Gas's cost efficiency over the 2019 to 2022 period.

M3.EGI-4

Reference:

Exhibit M3, page 73, Table 3

Exhibit M3, page 75, Table 4

Exhibit M3, page 77, Table 5

Preamble:

PEG provides a partial regression output for the three econometric models it estimated at Tables 3, 4 and 5. Although PEG's work provides parameter estimates and t statics on the model's independent variables, it does not provide any evidence on Enbridge Gas's actual cost or predicted cost for any of three PEG models in any of the sample years. Moreover, there is no discussion of any diagnostic tests or sensitivity analyses designed to ensure that the econometric results models are robust and unbiased. Aside from the estimates presented in the aforementioned tables PEG does not present any of the standard statistics that would typically be presented for each of its models. In addition there is no discussion of any of the standard diagnostic tests that PEG used to determine if its models are robust and satisfy the assumptions required for ordinary least squares regression analysis.

Question(s):

a) Is Dr. Lowry aware of tests of "structural breaks" in econometric research?

b) Does Dr. Lowry believe the sudden amalgamation of Enbridge Gas Distribution and Union Gas could potentially give rise to a "structural break" in Enbridge Gas's cost data and cost performance after 2019? Please explain why or why not in detail.

c) Does Dr. Lowry believe the unprecedented Covid-related experience of 2020 to 2022 could potentially give rise to a structural break in Enbridge Gas's cost data and cost performance after 2019? Please explain why or why not in detail.

d) One common test of structural breaks is the Chow Test, which can be implemented straightforwardly with relatively little incremental cost.

   i) Please implement Chow Tests of PEG's econometric cost model, as applied to Enbridge Gas's cost performance, to test for structural breaks in each of the following years and sets of years:
      2018
      2019
      2020
      2021
      2022
   The entire periods: 2018 to 2021, 2019 to 2021, 2018 to 2022, 2019 to 2022 test would therefore compare Enbridge Gas's cost performance for the 2006-2019 and 2019 to 2022 periods.

   ii) Based on the results of these Chow Tests, please explain whether the econometric research indicates that there has been a structural break in any of the requested time periods.

   iii) Do the results of the Chow Tests have any implications for PEG's estimate of Enbridge Gas's total cost performance, or PEG's proposed stretch factor? Please explain in detail.

e) Please confirm, what is the "Change CIBS07 Cumulative" explanatory variable in Table 5 and how is it measured?

f) Please confirm, what is the "MEGA %MilesTx x 2020+" explanatory variable in Table 5 and how is it measured?

g) Please confirm, what is the "Electric Dummy" explanatory variable in Table 5 and how is it measured?

M3.EGI-5

Question(s):

a) Has Dr. Lowry recently provided econometric evidence that benchmarks the cost performance of energy utilities in Alberta?

b) Other than the current proceeding for Enbridge Gas, is the 2023 benchmarking evidence in Alberta the most recent, publicly available benchmarking evidence that PEG has undertaken?

c) Did the Alberta Utilities Commission (AUC) accept Dr. Lowry's benchmarking evidence presented in either 2022 or 2023?

d) In fact, doesn't the 2023 AUC Decision state that some of Dr. Lowry's benchmarking evidence is "implausible"?

e) In light of the AUC's recent, 2023 Decision, and the far greater complexity of benchmarking Enbridge Gas compared with the Alberta utility companies, how can Dr. Lowry assure the OEB that PEG's most-recently proffered evidence is not similarly "implausible"?

Aggregating TFP Results

M3.EGI-6

Reference:

Exhibit M3, page 82

Preamble:

PEG states: "Table 7 reports annual growth rates in the O&M, capital, and multifactor productivities of all sampled U.S. gas utilities for each year of the full sample period. Even-weighted and size-weighted averages are both presented. Examining the even-weighted averages we find that total factor productivity averaged a 1.26% annual decline. O&M productivity growth averaged a slight 0.01% annual decline while capital productivity growth averaged a more substantial 2.17% annual decline. As for the cost-weighted averages, total factor productivity averaged a 1.54% annual decline."

Question(s):

One important issue for estimating total factor productivity trends for multiple companies is how individual company results should be aggregated into a single TFP measure. There are two general approaches to this issue: 1) compute a simple average of each sampled utility's TFP growth (even-weighted); or 2) weight the data of different companies (size-weighted or cost-weighted).

a) Please confirm that for Dr. Lowry's full-sample TFP results, industry TFP declined by 1.26% per annum when sampled utilities were even-weighted, and industry TFP declined by 1.54% per annum when sampled utilities were cost-weighted.

b) Please confirm that Dr. Kaufmann's full-sample, cost-weighted TFP analysis estimates that industry declined by –1.52% per annum.

c) Please confirm that when Dr. Kaufmann and Dr. Lowry both estimate TFP trends using the full industry sample and cost-weighted averages, there is only a difference of two basis points between their estimated TFP trends (i.e. -1.54% for Dr. Lowry, and –1.52% for Dr. Kaufmann).

d) Does Dr. Lowry believe that if two TFP studies estimate industry TFP trends that differ by only two basis points, it is reasonable to characterize these TFP estimates as "robust." Please explain why or why not.

e) Does Dr. Lowry generally prefer to compute TFP using even-weighted rather than cost-weighted /size-weighted data?

f) Please explain the benefits Dr. Lowry believes are associated with the even-weighted approach.

g) If Dr. Lowry believes that both approaches are potentially reasonable, please explain what criteria he uses for deciding whether to compute even-weighted rather than size-weighted TFP trends.

h) Suppose, Dr. Lowry was retained to compute the TFP trend for the Ontario gas distribution industry, comprised of Enbridge Gas with over 3.9 million customers; and EPCOR Ontario, which serves approximately 8000 customers. Would Dr. Lowry use even-weighted or size-weighted methods?

i) Has Dr. Lowry ever recommended that "econometric research typically assigns the same weight to every utility regardless of size"?

j) Other than Dr. Lowry's own TFP studies, please provide a list of every North American TFP study he is aware of where the research "assigned the same weight to every utility regardless of size." In each instance, please identify the year and Docket number for the study, and please cite the page numbers and/or workpapers which confirm that TFP trends were estimated using simple averages rather size-weighted data.

k) In particular, please indicate whether TFP studies submitted in the seven Massachusetts dockets listed below used weighted data or simple averages when computing TFP trends.

- 2023, D.T.E. 03-40
- 2005, D.T.E. 05-27
- 2017, D.P.U. 17-05
- 2018, D.P.U. 18-150
- 2019, D.P.U. 19-120
- 2020, D.P.U. 20-120
- 2022, D.P.U.,22-22

l) Please also confirm that Massachusetts Department of Public Utilities has reviewed and approved more TFP studies for utility incentive regulation plans than any other North American regulator.

“Custom Enbridge Gas Peer Group” and Measurement of TFP Trends

M3.EGI-7

Reference:

Exhibit M3, page 83

Preamble:

At page 83, Table 7 of the PEG Report shows that PEG estimated a –1.54% TFP growth trend for the U.S. gas distribution industry over the 2004-2022 period. This –1.54% TFP trend results when PEG computes TFP for the entire gas distribution industry and weights the TFP results of individual companies. These are both standard, rigorous, and long-established practices for estimating TFP trends for energy utilities over the last 30 years.

It is also noteworthy that Dr. Lowry’s industry TFP results are nearly identical to Dr. Kaufmann’s results. Using a somewhat different methodology, Dr. Kaufmann estimated a -1.52% TFP trend for the gas distribution industry over the 2006-2022 period. Together, the Lowry and Kaufmann studies imply that a gas distribution TFP estimate a few basis points below –1.50% is robust and amply supported by alternative productivity methods.

However, Dr. Lowry is not recommending that his industry TFP results be applied in the IRM for Enbridge Gas. Dr. Lowry explains this decision by stating:

> National average TFP trends from the United States do not provide a suitable basis for establishing an X factor for EGI. The principal reasons for this are as follows.
>
> - The productivity factor should reflect to the extent practicable the business conditions that EGI will face going forward.

- Casual empiricism supported by our econometric cost research suggests that some of the biggest drivers of declines in US gas utility productivity in the last 15 years are not relevant to EGI's situation going forward. In particular, EGI has few cast iron and bare steel mains and is not likely to face the costly transmission safety mandates that many gas transmission providers in the States contended with during the sample period. EGI's early replacement of its cast iron and bare steel mains should prospectively slow its cost growth due to the depreciation of replacement plant.

A more reasonable productivity growth peer group for Enbridge would accordingly be U.S. utilities that started the sample period with little CIBS, did not own much transmission capacity, and had a fairly normal rate of customer growth on average.

Question(s):

a) What is Dr. Lowry's view about the impact of the Phase 1 Decision and the subsequent Bill 165 on the business and operating environment for Enbridge Gas over the 2025 to 2028 term as compared to the business and operating environment during the deferred Rebasing term.

b) In order for Enbridge Gas to maximize its incentives for the 2025 to 2028 term, shouldn't the incentive regulation mechanism be consistent with the "competitive market paradigm", in which incentive regulation plans are designed to emulate the outcomes and incentives of competitive markets? Please explain.

c) Doesn't the application of the competitive paradigm require that parameters of incentive regulation plans, including the productivity factor, be calibrated using industry-wide measures of TFP growth? Please explain why or why not.

d) Given the current environment, wouldn't Dr. Lowry agree that a productivity factor based on industry-wide TFP trends will better reflect to the extent practicable the business conditions that Enbridge Gas will face going forward? Please explain why or why not.

e) What specific evidence does Dr. Lowry have to support the view that Enbridge Gas "is not likely to face the costly transmission safety mandates that many gas transmission providers in the States contended with during the sample period"?

    i) Do Canadian regulators and policymakers have less interest in pipeline safety than U.S. policymakers and regulators? If not, why is it reasonable to expect that there would be substantial differences in safety standards between U.S. and Canadian gas utilities over the long run?

    ii) Is it more reasonable to expect Enbridge Gas's safety-related expenses to become more rather than less similar to those of U.S. utilities going forward? Please explain.

f) At page 83, Dr. Lowry's primary reason not to use industry-wide TFP estimates is provided, PEG states: "Casual empiricism supported by our econometric cost research suggests that some of the biggest drivers of declines in US gas utility productivity in the last 15 years are not relevant to EGI's situation going forward. EGI's early replacement of its cast iron and bare steel mains should prospectively slow its cost growth due to the depreciation of replacement plant."

   i) Beyond "casual empiricism" does Dr. Lowry have any specific data or evidence to support his hypothesis that "EGI's early replacement of its cast iron and bare steel mains should prospectively slow its cost growth due to the depreciation of replacement plant." If so, please provide these data.

   ii) Is Dr. Lowry aware that Enbridge Gas effectively replaced all its cast iron assets by 2012?

   iii) Please see Table 1 below which, examines the average annual growth in Enbridge Gas's capital stock, for 1998 through 2012, or the years in which Enbridge Gas was replacing cast iron, and the 2012-2022 period for the 10 years after aged cast iron had been replaced. These growth rates have been computed for Enbridge Gas's distribution operations as well as its overall operations.

Table 1

Periods	Distribution Only	All Operations
1998 to 2012	3.61% per annum	3.45% per annum
2012 to 2022	3.68% per annum	3.70% per annum

It can be seen that during the 1998 to 2012 period when Enbridge Gas was replacing cast iron and bare steel assets, Enbridge Gas's capital grew at an average annual rate of 3.61% for Enbridge Gas's distribution (and allocated general capital) services, and 3.45% per annum for all of Enbridge Gas's operations. However, in the 2012 to 2022 period, Enbridge Gas's capital stock grew by 3.68% per annum for distribution services and 3.70% per annum for all services. Capital stock therefore grew more rapidly in the second period.

Dr. Lowry has hypothesized that Enbridge Gas's capital expenditures would decline after programs to replace cast iron and bare steel assets had been completed.

Does this empirical evidence lead Dr. Lowry to amend his prediction that Enbridge Gas's cost growth is likely to slow due to the Company's "early replacement" of cast iron and bare steel assets? Relatedly, does this analysis reduce Dr. Lowry's emphasis on cast iron and bare steel replacement as the most critical cost driver variable? If not, please provide additional evidence that supports Dr. Lowry's hypothesis and emphasis on the replacement of cast iron and bare steel assets.

g) How does Dr. Lowry define “fairly normal rate of customer growth”?

M3.EGI-8

Reference:

Exhibit M3, page 84

Preamble:

Dr. Lowry has proposed to estimate TFP trends using a small sample of eleven utilities that appear to have little in common with Enbridge Gas. Throughout his 30-year career as an incentive regulation consultant, Dr. Lowry’s work has mainly focused on estimating industry TFP trends using large samples of utility companies.

At page 84 of the PEG report, Dr. Lowry justifies this choice, saying that:

> A reasonable productivity growth peer group for Enbridge would accordingly be U.S. utilities that started the sample period with little CIBS *(i.e.* cast iron and bare steel), did not own much transmission capacity, and had a fairly normal rate of customer growth on average. We have developed a peer group consisting of all sampled utilities that, specifically,
>
> - had distribution plant exceeding 80% of total gross plant value
> - relied on CIBS mains for less than 5% of their distribution line length in 2007.
>
> We then removed the two utilities with the most rapid customer growth during the sample period to better reflect EGI’s customer growth prospects going forward.
>
> Eleven utilities satisfied these criteria. Their customer growth averaged 0.95% annually during the sample period.

Question(s):

a) Did Dr. Lowry provide TFP evidence in the MAADs regulatory proceeding that approved Enbridge Gas’s current IRM?

b) In that MAADs proceeding, was Dr. Lowry’s proposed TFP and benchmarking evidence developed using a large sample of U.S. gas distribution utilities?

c) Please identify how many sample utility companies Dr. Lowry used to estimate industry TFP trends in in the MAADs proceeding, which approved Enbridge Gas’s current IRM.

d) Have Enbridge Gas’s business conditions changed substantially since the MAADs proceeding that approved the X factor in Enbridge Gas’s current IRM? If so, please describe in detail these substantial changes in Enbridge Gas’s business conditions.

e) In particular was the issue of cast iron and bare steel replacement, which plays a dominant role in Dr. Lowry’s current recommendations, markedly different in 2019 than it is in 2024? Please explain in detail.

f) In the MAADs proceeding, did Dr. Lowry link the selection of utility companies used to estimate TFP trends to those firms' relative cast iron and bare steel assets in any previous year? Please describe in detail.

g) In any previous TFP study, has Dr. Lowry selected companies to be used for TFP or benchmarking research based on their shares of cast iron and bare steel assets in a previous year? If so, please identify all such TFP estimation projects, by year and docket number, as well as the specific criteria Dr. Lowry used to select sample companies based on previous cast iron and bare steel asset levels.

h) If Dr. Lowry has not previously selected sample companies for TFP research based on their past levels of cast iron and bare steel assets, please explain in detail what developments, or new information, led Dr. Lowry to select companies for his current, proposed TFP research based on their previous shares of cast iron and bare steel assets.

i) Please confirm that in 2023, Dr. Lowry provided TFP evidence in Alberta that was developed using a sample of 90 utility companies.

j) Why is it appropriate for Dr. Lowry to use 90 companies to estimate TFP trends in 2023, and to reduce the number of sampled companies by 88% when estimating TFP trends one year later? Please explain in detail.

k) Has Dr. Lowry previously recommended custom, or customized, TFP results in Alberta?

l) Please identify the year and docket number for every TFP and/or benchmarking study where Dr. Lowry has recommended custom or customized TFP targets in Alberta.

m) Has the Alberta Utilities Commission (AUC) ever accepted Dr. Lowry's proposed, customized TFP evidence? Please explain in detail.

M3.EGI-9

Reference:

Exhibit M3, page 41

Preamble:

Table 1 of the PEG report identifies over 100 examples of what the Table calls "North American Energy Utility Productivity Evidence."

Question(s):

a) How many of the examples in Exhibit M3, Table 1 provide evidence of industry TFP trends? Please identify each study in Exhibit M3, Table 1, that measures TFP trends for a utility industry.

b) How many of the utility industry TFP studies identified in Exhibit M3, Table 1 were computed using 11 or fewer sampled utilities? Please identify each industry TFP study calculated using 11 or fewer companies. Please also include the year and Docket Number where these studies were provided.

c) Please confirm that six of the 11 utilities Dr. Lowry has proposed to use to estimate industry TFP trends are based in the midwest United States.

d) Please confirm that four of these six midwest companies are based in Wisconsin, one is based in Illinois, and one is based in Indiana.

e) In light of the diversity within the US gas distribution industry, does Dr. Lowry believe it is appropriate for more than one-third of the companies used to estimate industry TFP trends to be based in a single state (*i.e.,* Wisconsin). Please explain.

f) Please confirm that one of the other Midwest utilities, North Shore Gas, serves approximately 150,000 customers in a largely affluent, suburban territory north of Chicago.

g) Please confirm that four of the remaining five peers serve territories largely in the Northwest United States.

h) Please confirm that much of the Northwest U.S. is growing briskly and therefore adding gas distribution customers at a rate far above the U.S. national average.

i) Please confirm that the remaining peer, New York State Electric and Gas, serves a territory in New York that largely borders Pennsylvania and is far from the densely populated Eastern seaboard.

j) Please confirm that, on average, Dr.Lowry’s eleven proposed peers served 411,596 customers in 2022.

k) Please confirm that Enbridge Gas’s customer base in 2022 exceeded 3.9 million customers and was therefore nearly 10 times greater than the average customer numbers served in Dr. Lowry’s Custom IR Peer Group.

l) Please confirm that the population of the largest city in the territories of the 11 selected peers averaged 355,909.

m) Please confirm that, in 2022, the population of the city of Toronto was 3,025,647, while the estimated population of the Toronto metropolitan area was 6,471,850.

n) Please confirm that, over the 2013 to 2022 period, average customer growth for Dr. Lowry's 11 company peer group was equal to 1.44%.

o) Please confirm that the 1.44% grow rate in Dr. Lowry's sample is more than double the 0.68% customer growth trend for the U.S. gas distribution industry computed in Dr. Kaufmann's TFP study.

p) Please also confirm that Enbridge Gas's recent growth in customer numbers is becoming more similar to that of the overall U.S. industry.

q) Please confirm that customer growth rates have a direct impact on estimated TFP growth in both Dr. Lowry's and Dr. Kaufmann's TFP studies, because in both cases gas distribution output is measured by the growth in customer numbers.

r) Since Dr. Lowry's peer group has an average rate of customer growth of 1.44% per annum, and Dr. Kaufmann's research shows a 0.68% average annual increase in customer numbers, please confirm that the difference in customer growth between these studies is equal to 0.76%.

s) Please confirm that, all else equal, a differential of 0.76% in customer growth will lead directly to a 0.76% or 76 basis point, increase in estimated TFP growth.

t) Therefore, all else equal, please confirm that restricting the TFP sample to the 11 companies recommended by Dr. Lowry will increase the industry's estimated TFP trend by 76 basis points, compared with the full-sample TFP trend.

u) Dr. Lowry's econometric model for capital cost performance includes an "urban core" measure as an independent variable. When implementing this model, were any of Dr. Lowry's 11 selected peers designated as serving an "urban core"? Please explain.

v) Did Dr. Lowry's capital cost econometric model designate Enbridge Gas as having an urban core?

w) If none of the selected peers serve an urban core, while Enbridge Gas does serve an urban core, please explain how the 11 selected peers are representative of Enbridge Gas's business conditions? In doing so, please consider the importance of the urban core issue in utility cost benchmarking in Ontario.

M3.EGI-10

Reference:

Exhibit M3, page 73, Table 3

Exhibit M3, page 75, Table 4

Exhibit M3, page 77, Table 5

Preamble:

PEG provides its regression outputs in the referenced tables but does not provide any information of how these models were estimated.

Questions:

a) For the models set out in the referenced tables please confirm that each of the models was estimated using ordinary least squares. If not confirmed please explain the estimation procedure used for each model.

b) For the models set out in the referenced tables please provide the functional form for each model. For example, are the models presented estimated using a linear specification, log-linear specification, log-log specification or some other specification?

c) The number of observations provided in each of the referenced tables equals 859 observations with a sample period of 2008 to 2022.

    i) Were the models presented in the referenced tables estimated using cross-sectional time-series/panel data?

    ii) Were the models set out in the referenced tables estimated using data for all 57 companies provided at Exhibit M3, page 64, Table 2? If not, please provide a table for each model which shows each company included in the data used to estimate each of the models.

    iii) Please explain how the number of observations for each of the referenced models (859) is greater than the number of years included in each respective model the sample times the number of companies (57 companies times 15 years = 855 observations).

M3.EGI-11

Reference:

Exhibit M3, page 73, Table 3

Exhibit M3, page 75, Table 4

Exhibit M3, page 77, Table 5

<u>Preamble:</u>

PEG provides its regression outputs in the referenced tables but does not provide any of the diagnostic tests typically applied to the results of an econometric model.

<u>Questions:</u>

a) For each of the models set out in the referenced tables please provide the full statistical results of any diagnostic tests used to determine if the models exhibit the following:

   i) Serial correlation

   ii) Heteroskedasticity

   iii) Autoregressive conditional heteroskedasticity (ARCH)

b) If none of these diagnostic tests were completed please explain why not?

c) Each of the three models presented include the following independent variables: Number of Customers, Number of Customers Squared and Customer Growth since 2008. The latter two independent variables are a function of the former which suggests they would be highly correlated with each other. Did PEG conduct any diagnostic tests to determine if these variables are correlated? If yes, please provide those results. Please explain why multicollinearity amongst these variables is not an issue for each of the referenced models.