



PUBLIC INTEREST ADVOCACY CENTRE
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February 10, 2023

VIA E-MAIL

Ms. Nancy Marconi
Registrar (registrar@oeb.ca)
Ontario Energy Board
Toronto, ON

Dear Ms. Marconi:

Re: EB-2022-0200 Enbridge Gas Inc. (EGI)
2024 Cost of Service distribution, transmission and storage rates
Interrogatories of the Vulnerable Energy Consumers Coalition (VECC)

Please find attached questions of VECC in the above-noted proceeding. We have also directed a copy of the same to EGI. As per the Board's instructions in Procedural Order No. 1 we have used the exhibit and tab numbers as the reference for naming interrogatories. The numbering for each interrogatory is continuous. We have included some question where we were uncertain as to which phase of the hearing they should be put forth. EGI is invited to defer these questions if appropriate.

Yours truly,

Mark Garner
Consultants for VECC/PIAC

Email copy:

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For interrogatory clarifications please contact Mark Garner at 647-408-4501 or markgarner@rogers.com

REQUESTOR NAME	VECC
TO:	Enbridge Gas Inc. (EGI)
DATE:	February 10, 2023
CASE NO:	EB-2022-0200
APPLICATION NAME	2024 Cost of Service distribution

Exhibit 1

Issue A: Amalgamation customer benefits/energy transition/indigenous customers/relevant directions

1-VECC-1

Reference – Exhibit 1, Tab 9, Schedule 1, Tables 1, 2,3

- a) Please clarify whether the “Potential” savings shown in Table 1 are net of integration costs and are calculated as the net total over 10 or 5 years?
- b) Please clarify whether the savings shown in Tables 2 & 3 are net of the integration costs as shown in Table 5.

1-VECC-2

Reference – Exhibit 1, Tab 9, Schedule 1, Table 5

- a) Please update Table 5 to include 2022 actual results.

1-VECC-3

Reference – Exhibit 1, Tab 9, Schedule 1, Table 6

- b) Please update Table 6 to include 2022 actual results.
- c) Please provide a table similar to Table 6 which shows integration related in-service additions by year along with the additions to depreciation related to those additions (i.e., as per continuity schedules).

1-VECC-4

Reference – Exhibit 1, Tab 15, Schedule 1, Attachment 1

- a) Please clarify how normalized system reinforcement costs (NSRC) are calculated in any given year/project. Specifically provide a sample calculation to show its derivation.
- b) Was the concept of NSRC discussed in EB-2020-0094 or is the concept new to this application?
- c) In its Decision in EB-2020-0094 the Board noted evidence of Enbridge which stated: *“Enbridge Gas stated that this does not mean that it does not apply a PI of 0.8, but that this lower PI threshold is the exception generally reserved for system reinforcement projects, and not the rule.”* Please explain how this statement is consistent with the NSRC concept proposed in this application.

1-VECC-5

Reference – Exhibit 1, Tab 15, Schedule 1, Attachment 1

“Refunds of CIAC may be requested by customers when the actual customer count on a system expansion project exceeds the original forecast.”

“No interest is payable on refunds, and only those customers who made the original contribution are eligible for a refund.”

- a) How will a customer know if a project’s actual customer count has exceeded the original forecast?
- b) Is the calculation for exceeding (or not meeting) the forecast done on an annual basis or at the end of a given period? If the latter please specify how the refund amount will be calculated.
- c) What is the reason for not providing interest on overcollection of CIAC amounts?
- d) What is the reason for attaching the refund to the original customer rather than the property? And is this policy the same for large volume customers, residential and commercial customers?

1-VECC-6

Reference – Exhibit 1, Tab 15, Schedule 1, Attachment 1

“When a CIAC is required for a project that serves more than one general service residential and small commercial customers, the CIAC is allocated between the customers based on the annual consumption forecast”

- a) Is the CIAC calculated on a forecast or actual basis and if the former is any adjustment (refund/charge) made to the CIAC subsequent to actual consumption?

Reference – Exhibit 1, Tab 15, Schedule 1, Attachment 1

“Small volume customers (SVC) on a project that is denoted as SES or TCS, do not have the option of paying a CIAC in lieu of the SES or the TCS.”

- a) It is unclear to us when or what differentiates a project that attracts the use of CIAC and one that uses the SES/TCS funding mechanisms – please clarify.
- b) Is the above noted mutual exclusion as between CIAC and SES/TCS meant to prohibit both the use of CIAC where SES/TCS is used and to exclude them being used in conjunction with each other (i.e., could **both** a CIAC and SES/TCS be applied to make a project reach a PI of 1.0)?

1-VECC-7

Reference – Exhibit 1, Tab 14, Schedule 4

- a) What is the net revenue requirement impact of eliminating the OBA program in 2024?

1-VECC-8

Reference – Exhibit 1, Tab 14, Schedule 2

- a) Please provide a list of the types of operating expenses incurred in the NGV program.
- b) Attachment 1, which shows the costs and revenues for the NGV program does not include any capital costs. Are there no capital costs incurred by the program?
- c) Please explain how expanding the NGV program to the former Union territories is consistent with the Utility’s commitments to reduce GHG emissions?

1-VECC-9 (possible Phase 2 Issue)

Reference – Exhibit 1, Tab 7, Schedule 1

- a) Please provide the OEB Scorecard in the format of Attachment 1 but for the years 2013-2016 (EGD and Union).
- b) Please update the Scorecard at Attachment 1 to include 2022 results
- c) A review of the measures EGI is seeking relief from meeting and the historical data prior to amalgamation suggest that the two prior Utilities were able to meet all the performance measures with the exception of Time to Reschedule Missed Appointments – where both utilities were within .03% of meeting the target. Since amalgamation there has been a notable decline in a number of performance metrics – for example emergency call response has fallen from around 97-99% to 95.2% after amalgamation. Please outline the changes were made to the call centre operations subsequent to amalgamation.
- d) Please provide (separately) the number of telephone calls, email and other contacts (social media etc.) for each year 2013 through 2022.
- e) Does EGI outsource call center activity? If so please provide the performance measurements required by that contract.

Exhibit 2

Issue B: Rate Base

2-VECC-10

Reference: Exhibit 2, Tab 1, Schedule 1, Table 2

- a) Please update Table 2 for 2022 actual results.

2-VECC-11

Reference: Exhibit 2, Tab 3, Schedule 2, Table 2

- a) Please calculate the working capital allowance for 2024 without including the new lead/lag categories (i.e., lines 3, 4 &5).
- b) Hydro One Distribution's latest proposed net cash working capital requirement for the 2023 test year was 6.1% of OM&A from revenue requirement and cost of power (EB-2021-0110). What is the equivalent percentage for EGI's working capital?
- c) Who is (are) the author(s) of the 2021 Lead-Lag Study filed at Attachment 1. If they are employees of EGI or its affiliates was any independent study of working capital requirements undertaken?

2-VECC-12

Reference: Exhibit 2, Tab 4, Schedule 2, Table 3, page 17

- a) EGI shows the harmonized capitalization amount in 2024 to in the amount of \$310.5 million. Please confirm (or correct) that this amount is based on the 2024 O&M and Capital budgets used in the calculation of 2024 rates.
- b) Does EGI propose to make future adjustments in rates to account for the fact that actual capitalized overheads during the IRM rate period (i.e., 2025-2028) will change in relationship to the actual capital projects completed in any given year? If yes, please explain how these adjustments are to be made.
- c) Who is (are) the author(s) of the Overhead Capitalization Study at Attachment 1? If they are employees of EGI or its affiliates was any independent study of capitalization policy undertaken?

2-VECC-13

Reference: Exhibit 2, Tab 5, Schedule 2, Table 1Schedule 3, Table 6

- a) Please update Table 6 for 2022 actual results.

2-VECC-14

Reference: Exhibit 2, Tab 5, Schedule 3

- a) Please provide a construction status update of the Dawn to Corunna Replacement project which includes the most recent project Gantt chart.

B-VECC-15

Reference: Exhibit 2, Tab 6, Schedule 1

1. Please modify Table 5 (page 44) to produce a table list by separate year, subject to LTC which are anticipated to go into service in either 2023, 2024 and 2025. Please also add to the table any projects that may not require LTC approval but would require franchise or other regulatory approvals (specify).
2. For each project in the table requested above please show:
 - i. project related capitalized overheads separately from the total estimated project costs;
 - ii. the expected start and completion/in-service date by month/year;
 - iii. the current application status (i.e., expected filing date or filed date, notice date, decision date etc.).

2-VECC-16

Reference: Exhibit 2, Tab 6, Schedule 1, Table 4

With respect to Table 4 the evidence is “*Enbridge Gas does not anticipate seeking ICM recovery for these projects.*”

- a) What circumstances would need to change for EGI to revisit its current anticipation of no ICM requests during the rate period?

2-VECC-17 (possible Phase 2 Issue)

Reference – Exhibit 2, Tab 5, Schedule 2, page 7/ Tab 6, Schedule 2, Appendix B, page 46 of 123.

- a) Please provide the annual LCEP capital and OM&A expense for each year 2021 through 2026.
- b) Please explain the difference between the \$7 million in spending noted at Exhibit 4 (page 7) and the \$9,050,523 at noted in Exhibit 2 Appendix B (page 46).
- c) Please explain the difference between the \$12 million for the Grid Study noted in Exhibit 4 and the \$15,523,163 “Comprehensive techno-economic feasibility study of blending hydrogen” noted in Exhibit 2 Appendix B.
- d) What is the economic benefit to ratepayers of this project?

2-VECC-18

Reference: Exhibit 2, Tab 6, Section 5.4.7 (REWS)

- a) Please provide a list of all properties that were sold in each year 2019 through 2022 and provide the net (of fees) sale price.
- b) Please provide a list of the forecast sales of properties in 2023 and 2024 and the current assessed value of those properties
- c) Please provide a list of the properties forecast to be purchased in 2023 and 2024 and the current actual or forecast cost of those properties.

Exhibit 3

Issue C: Load and Revenue Forecasts

3-VECC-19

Reference – Exhibit 3, Tab 2, Schedule 2- Guidehouse Forecasting Benchmarking Study, page 24

For many of the utilities, however, some stabilization mechanism exists to provide consumers and the utility with bilateral protection from weather volatility. In some cases, this is explicit in the mechanism (e.g., the weather normalization adjustments of utilities D, F, G, and J), in other cases it appears to be implicit (e.g., utilities A, B, C, E, and I). In most of the instances in which an explicit weather-related revenue stabilization mechanism exists, there also exists a revenue decoupling mechanism which includes revenues collected (or credits disbursed) as part of intra-season weather normalization adjustments.

- a) It is not clear to us what are the distinguishing characteristics of “implicit” normalization as compared to “explicit” methods. Please elucidate.
- b) How many of the comparator utilities use normalized variance accounting practices in the same fashion as EGI (former EGD and Union Gas)? For those that use NAC accounting how of these utilities use a symmetric account in a similar fashion as EGI?

3-VECC-20

Reference – Exhibit 3, Tab 2, Schedule 2- Guidehouse Forecasting Benchmarking Study, page 30/ Schedule 5

EGI is proposing to use 50/50 Hybrid (average of 20-yr Trend and 10-yr MA) for the Central weather zone, and 10-yr MA for the remaining weather zones. Selection of the forecasting methodologies for each weather zone was done by using the evaluation framework that compares ten different methodologies (including methodologies used by EGD and Union rate zones) through their forecasting performance (accuracy, symmetry and stability criteria)

- a) How many utilities in the comparator group use different methods of determining Heating Degree Day Forecasting for different parts of their franchise?
- b) Please explain how multiple HDD forecasting methodologies for rate zones is consistent with a moving to a single base temperature (i.e., to 15° C).
- c) All other things remaining the same what impact does changing the base temperature to 15° have on forecasting revenues (i.e., does it lead to any systemic increase or decrease)?

3-VECC-21

Reference – Exhibit 3, Tab 1, Schedule 1, Table 2 (line 3)

- e) What explains the lack of any storage revenues forecast for 2024?

3-VECC-22

Reference – Exhibit 3, Tab 2, Schedule 1, Attachment 1, pages 4-7/ 13-16

- c) Please update the Revenue Tables to show 2022 actual results.
- d) Please update the Comparison of Revenue Tables for actual 2022 results.

3-VECC-23

Reference – Exhibit 3, Tab 2, Schedule 5, Attachment 2, Tables 1 and 2

- a) Using the data period 2012 to 2021 and the rate classes shown in Tables 1 and 2 please provide an analysis for each of the three normalization methods (EGD/Union/Proposed) which examines how the methods rank by number of degree days produced. The purpose of this question is to understand if any of the three methods produces significantly different results for any class of customers as compared over the 2012-2021 time period.

3-VECC-24

Reference – Exhibit 3, Tab 2, Schedule 6, page 7

“The initial new construction and the replacement customer forecast, determined using econometric/historical trend approaches, was then reviewed by Enbridge Gas’s Construction, Operations, and Sales teams, who gathered market information through direct contact with builders, developers, and municipalities and adjustments were made to the forecast based on this information if required.”

- a) Please delineate what manual adjustments were made to the data used in the regression analysis.
- b) Specifically, please provide the raw data and the adjusted data.

3-VECC-25

Reference – Exhibit 3, Tab 2, Schedule 5, page 28

Rather, Enbridge Gas is proposing the establishment of a variance account for volume variances until SFVD rate design is approved by the OEB and fully implemented by Enbridge Gas.

- a) In light of the proposed movement to SFVD rate design would it be simpler and less costly for EGI to maintain the current NAC accounting until that (presumed) change?
- b) In the absence of Board direction to the contrary why would EGI not prefer to continue with the historical methodologies until approval is provided for an SFVD rate design?

3-VECC-26

Reference – Exhibit 3, Tab 2, Schedule 6, Table 1, page 9

“Shrinkage customers are defined as the customers that Enbridge Gas stops getting revenue from (due to meter consolidations, locked customers etc.).”

- a) Please explain how in the year 2019 the number of “Shrinkage Customers” can be a positive figure (i.e., 335).
- b) Please explain the meaning of the term “locked” customer in both the Union and EGI rate zones.

3-VECC-27

Reference – Exhibit 3, Tab 2, Schedule 6

- a) What is the minimum advance notice required for a new natural gas residential connection? In answering, please distinguish between individual requests and those made by property developers.
- b) For purposes of new meter connections does EGI undertake a monthly connection plan? If so please provide the plan for all the currently projected months in 2023.
- c) Does EGI collect data from developers on new construction request for natural gas service? If yes please provide the most recent report for connections in 2023.

3-VECC-28

Reference – Exhibit 3, Tab 2, Schedule 6, Attachment 1

- a) Please explain how Replacement customers are forecast?
- b) What accounts for the dip in the number of Replacement customers in 2023 as compared to the year prior and after (i.e., 5,066/4,878, 5,639)?

3-VECC-29

Reference – Exhibit 3, Tab 2, Schedule 6, page 7/Attachment 1

“The initial new construction and the replacement customer forecast, determined using econometric/historical trend approaches, was then reviewed by Enbridge Gas’s Construction, Operations, and Sales teams, who gathered market information through direct contact with builders, developers, and municipalities and adjustments were made to the forecast based on this information if required. “

- a) Using the table of customers at Attachment 1 please show for the years 2022, 2023 and 2024 the results of the econometric modeling separately from changes made to those results based on other information.
- b) Please list all manual adjustments and describe the basis for the adjustment.

3C-VECC-30

Reference – Exhibit 3, Tab 2, Schedule 7, page 3

“After the base volume forecast is developed, certain adjustments are applied to the forecast to account for known factors over the forecast period.”

- a) Please list all the adjustments done to the general service econometric forecast and explain whether the method of that adjustment. Please explain whether the adjustment is part of modeling analysis, other data (please describe how data is used for adjustment, or other manual adjustment methods.

3-VECC-31

Reference – Exhibit 3, Tab 2, Schedule 7, Attachment 1

- a) It is unclear to us how the general service normalized class volumes shown in Attachment 2 are derived from the Rate Class volumes shown in Attachment 1. For example, for the year 2012 the EGI residential volume is 7,476.4 (page 2). How is this figure derived from the 2012 Rate 1 and Rate M1 classes (4,609.0 and 2,902.6 respectively at page 1). Please explain.

3-VECC-32

Reference – Exhibit 3, Tab 2, Schedule 7, Attachment 1

- a) Please update Attachment 1 for 2022 actual results.

3-VECC-33

Reference – Exhibit 3, Tab 2, Schedule 6, Attachment 1

- a) Please update the average number of customers table to show actual 2022 results.

3-VECC-34

Reference – Exhibit 3, Tab 3, Schedule 1, Attachments 1 & 2

- a) Please update Attachments 1 & 2 to show 2022 actual results.

3-VECC-35

Reference – Exhibit 3, Tab 4, Schedule 1, Attachment 1

- a) Please explain the elimination of the “Ratepayer Portion of Exchange Revenue (Union) after 2018 (line 18 Attachment 1, page 2 of 3).

3-VECC-36

Reference – Exhibit 3, Tab 5, Schedule 1, Table 1

- a) Please update Table 1 (Other Revenues) to show 2022 actual results.

3-VECC-37

Reference – Exhibit 3, Tab 5, Schedule 1, Table 2/ Tab 2, Schedule 6 Attachment 1

Table 2
Other Revenue Account Opening Charges

Line No.	Particulars (\$ millions)	Utility	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>
			Actual (a)	Actual (b)	Actual (c)	Estimate (d)	Bridge Year (e)	Test Year (f)
1	New Account (1)	EGI	9.9	9.7	10.8	12.5	11.0	9.4
2	Meter Unlocks (2)	EGI	2.6	0.1	0.2	2.6	2.6	4.5
3	Total Account Opening Charges		12.4	9.8	11.1	15.1	13.6	13.9

- Please provide a table showing the number of customers moves for the years 2019 through 2024 (forecast)
- Total Customer Additions (New Construction and Replacements) increased from 42,482 to 42,642 as between 2021 and 2022 (estimate), or 160. The increase in new account revenue in that same period was \$1.7 million. Assuming the number of customer moves is relatively stable year on year what explains this relatively large dollar increase in 2022?
- Please update Table 2 to show actual 2022 results.

3-VECC-38

Reference – Exhibit 3, Tab 5, Schedule 1, Table 1

- Has EGI undertaken a cost-benefit analysis of the NGV program in the last 5 years?

3-VECC-39

Reference – Exhibit 3, Tab 5, Schedule 1, Table 1

- What was the 2022 cost of operating the Open Bill Access Program?
- Please provide the Open Bill Revenue Variance Account (“OBRVA”) year-end balance for the years 2018 through 2023.

Exhibit 4

Issue D: Operating Expenses

4-VECC-40

Reference – Exhibit 4, Tab 2, Schedule 1, page 15

Table 3 <u>Other Third-Party Transportation Contracts</u>			
Line No.	Particulars (GJ/d)	Path	Contract Quantity (a)
<u>Upstream Pipeline/Transportation Service</u>			
1	Centra Transmission Holdings Inc. & Centra Pipelines Minnesota Inc.	Sprague to Union MDA	5,813
2	TransCanada Pipeline	Kirkwall to Union CDA	135,000
3	TransCanada Pipeline	Dawn to Union ECDA	8,000
4	St. Clair Pipelines L.P.	St. Clair Crossing	214,000
5	St. Clair Pipelines L.P.	Bluewater Crossing	127,000
6	2193914 Canada Limited	Vaughan to Lisgar	244,265

- Are any of the companies listed in Table 3 affiliates of EGI or its parent owner?
- Does EGI's parent have any financial interests in any of the companies listed in Table 3?

4-VECC-41

Reference – Exhibit 4, Tab 2, Schedule 4

Effective 2024, Enbridge Gas plans to adopt the approach of managing operational contingency using cost-based storage inventory targets.....

- What are the annual operational savings in the change in storage inventory targets?

4-VECC-42

Reference – Exhibit 4, Tab 2, Schedule 2, Table 1, Table 2

Table 1
April 2022 QRAM Reference Prices

<u>Line No.</u>	<u>Rate Zone</u>	<u>Reference Price</u>	<u>\$/GJ (1)</u> <u>(a)</u>	<u>\$/10³m³ (1)</u> <u>(b)</u>
1	EGD (2)	PGVA Reference Price	5.996	231.041
2	Union South	Dawn Reference Price	5.269	206.123
3	Union North East	Dawn Reference Price	5.269	206.123
4	Union North West	Alberta Border Reference Price	4.618	180.656

- a) For each of the 4 rate zones for each QRAM quarter please provide a table showing the QRAM reference price since amalgamation (2019) and the actual average price for the subsequent QRAM quarter.
- b) Why is the PGVA reference price for EGD shown in Table 1 (5.996) different from that shown in Table 2 (5.912)?

4-VECC-43

Reference – Exhibit 4, Tab 2, Schedule 2, page 6, par 19.

- a) In considering a harmonized reference price EGI seems to have considered using either existing reference prices or a single price. What consideration was given to creating gas supply zones based on NAESB transaction hubs? For example, Union EDA and Enbridge EDA share roughly the area of Ottawa-Kingston, whereas Union CDA and Enbridge CDA share Ontario south west and GTA region. Union WDA and NDA cover a large part of Northern Ontario. Such a plan might divide Ontario into three zones North, Southwest and East (or something similar). What benefits or issues might there be in aligning gas supply reference prices with gas supply transaction zones such as those described?

4-VECC-44

Reference – Exhibit 4, Tab 2, Schedule 3, page 31

- a) Please confirm (or correct) that under the design day methodology proposed by EGI all interruptible load is assumed to be curtailed. If this is not the case please explain why.

4-VECC-45

Reference – Exhibit 4, Tab 3, Schedule 1, page 10, Table 3

“Enbridge Gas proposes to determine the forecast for UFG based on a 3-year simple average of actual UFG volumes.”

- a) We are unable to replicate a three year simple average for the total UFG amount in 2024 test year of 270,370 10³m³ as shown in Table 3. Please show the derivation of this figure.
- b) Is the 3 year average derived from only past actual amounts or does the 2024 year use the 2023 UFG forecast?

4-VECC-46

Reference – Exhibit 4, Tab 4, Schedule 2

<u>Table 3</u> <u>Business Development & Regulatory O&M</u>									
Line No.	Particulars (\$ millions)	Utility	<u>2018</u> Actual (1)	<u>2019</u> Actual	<u>2020</u> Actual	<u>2021</u> Actual	<u>2022</u> Estimate	<u>2023</u> Bridge Year	<u>2024</u> Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Salaries & Wages	EGI	17.1	13.5	11.4	11.1	13.1	13.7	18.0
2	Contract Services	EGI	20.4	16.5	14.8	16.1	18.3	19.6	22.6
3	Sponsorships & Memberships	EGI	5.3	5.0	1.1	4.2	1.8	3.9	4.1
4	Other O&M	EGI	(0.2)	1.7	0.8	1.3	1.7	2.4	2.5
5	Total	EGI	42.6	36.7	28.1	32.7	34.9	39.6	47.2

- a) Please describe what type of costs are included under the ambit of “Other”.
- b) Please show the FTES for Business development for each year in the table.
- c) Please update Table 3 for 2022 actual results.

4-VECC-47

Reference – Exhibit 4, Tab 2, Schedule 1

Table 4
Customer Care O&M

<u>Line</u> <u>No.</u>	<u>Particulars (\$ millions)</u>	<u>Utility</u>	<u>2018</u> <u>Actual</u> <u>(1)</u> <u>(a)</u>	<u>2019</u> <u>Actual</u> <u>(b)</u>	<u>2020</u> <u>Actual</u> <u>(c)</u>	<u>2021</u> <u>Actual</u> <u>(d)</u>	<u>2022</u> <u>Estimate</u> <u>(e)</u>	<u>2023</u> <u>Bridge</u> <u>Year</u> <u>(f)</u>	<u>2024</u> <u>Test</u> <u>Year</u> <u>(g)</u>
1	Salaries & Wages	EGI	26.6	24.5	22.1	23.7	24.1	25.6	27.1
2	Contract Services	EGI	106.0	93.3	81.6	82.8	75.9	79.4	80.9
3	Bad Debt	EGI	10.6	9.0	10.7	13.2	14.1	17.5	21.5
4	Other O&M	EGI	9.8	3.9	3.2	(3.1)	4.2	1.4	5.6
5	Total	EGI	153.0	130.7	117.6	116.6	118.3	123.9	135.1

“Finally, the \$4.2 million increase in other O&M costs is driven by \$3 million from the previous year’s reduction from unapplied customer payments and \$1.2 million for the Company’s proposal to treat DCB as a utility activity” (pg. 22)

- We are unclear what is meant by this statement. Is EGI suggesting that \$4.2 million are not incremental and reoccurring costs in 2024? Please clarify.
- Please show the FTES for Customer Care for each year in the table.
- Please explain how the bad debt estimate for 2024 was derived.
- Please update Table 4 for 2022 actual results.

4-VECC-48

Reference – Exhibit 4, Tab 4, Schedule 2

“The Operations department at Enbridge Gas is responsible for the safe and reliable delivery of natural gas to approximately 3.8 million customers. The distribution system that serves these customers consists of more than 147,000 km of mains and services and more than 37,000 pressure regulating stations. The department is comprised of seven Regional Operations groups and Operations Services and Governance (OSG).”

- Does EGI maintain separate cost records for each of the regions?
- Is any analysis completed as between the practices, productivity initiatives, efficiencies etc. in each of the seven regions?

4-VECC-49

Reference – Exhibit 4, Tab 4, Schedule 2, Table 5, page 35

- a) Other O&M shows an increase from 2022 to 2023 from \$5.9 million to \$15.9 million. Paragraph 81 attributes this to rising insurance premiums. Please provide the 2021 - 2023 annual insurance premiums (line 5 “Other O&M”).
- b) For the years 2018- 2024 what is the total amount of costs (if any) that are not actual premium costs but forecast liabilities for deductibles on insurance policies (please provide, but separate out policies from Distributions Operations from all other policies in these years).
- c) Please provide a table showing all insurance premium costs for each year 2018 through 2024 and which separates those premiums recovered under CF costs and those recovered directly by the Utility. Please show separately any insurance related costs that are not paid premiums.

4-VECC-50

Reference – Exhibit 4, Tab 4, Schedule 2, Tables 6 & 7

- a) Please update Tables 6 and 7 for 2022 actual results.
- b) It is unclear to us why the “Other O&M” in Table 7 is a negative amount (deduction). If this is due to allocation of costs to unregulated storage please explain why this amount fluctuates from year to year and why beginning in 2022 the deduction to O&M reduces significantly.

4-VECC-51

Reference – Exhibit 4, Tab 4, Schedule 2 Table 8 / Tab 4 Schedule 3 Table 3

- a) Please provide examples of services provided by EAWM.
- b) Please specify how many FTEs in each year were allocated to this function and explain where these FTEs are physically located.
- c) How many FTEs are directly employed by EGI in HR? How many FTEs are allocated to this function in 2024 from Central Functions?
- d) Please confirm (or correct) that \$1.1 million of the \$4.7M increase in SCM is accounted for by a transfer of costs from Operations.

4-VECC-52

Reference – Exhibit 4, Tab 4, Schedule 3, Table 3

- a) Please show separately the TIS costs related to cyber security for each year 2018 – 2024.
- b) EGI states that a reason for the increase in TIS costs is “...*Industry shifts to ‘as a service’ models have resulted in shifting costs from capital to O&M over time.*” Please show the associated decrease in TIS capital related costs in each year 2018 through 2024.

4-VECC-53

Reference – Exhibit 4, Tab 4, Schedule 3, page 39

“In addition to receiving shared services through CFs, Enbridge Gas performs services and incurs expenses on behalf of affiliates, which are subsequently reimbursed and recovered from affiliates.”

- a) Please show the amount of the above mentioned reimbursements for each year 2018 through 2024 forecast.

4-VECC-54

Reference – Exhibit 4, Tab 4, Schedule 3 2, Schedule 1

- a) Please clarify if the United Way Simcoe Muskoka administers the LEAP program for all the EGI franchises (rate zones).
- b) Please show how the \$2.6 million in annual LEAP funding is calculated.

4-VECC-55

Reference – Exhibit 4, Tab 4, Schedule 3, Attachment 3 - Guidehouse CF Methodology Review

- a) With respect to the central functions summarized in Table 3-1 of the Guidehouse Report did Guidehouse undertake an audit of the listed service categories and descriptions to satisfy itself that these functions were being provided as described?
- b) Please explain the difference as between Table 6-2 and 6-3 in the Report and Table 3 at page 32 of Schedule 3.

4-VECC-56

Reference – Exhibit 4, Tab 4, Schedule 3 Table 3

- a) Please provide a table which shows for each category of CF costs for each year: (1) the total amount of costs in that category; (2) the EGI allocation (i.e., Table 3) and (3) the total number of affiliates/entities that the amount is allocated among.
- b) Please provide a list of all the entities in 2024 that are expected to be sharing in the costs of the programs shown in Table 3

4-VECC-57

Reference – Exhibit 4, Tab 5, Schedule 1

- a) Please confirm (or correct) that the incremental increase due to the proposed change in depreciation rates is \$168.9 million. If this is correct it is a significant change of more than 22% in costs. What accounting specific mitigation strategy is EGI proposing to introduce such a large change.
- b) Why should the Board not consider either harmonizing depreciation rates to those used by one of the former utilities or an average where they differ? Specifically address what harm results from a less drastic change to depreciation rates.
- c) If the Board rejects harmonized rates please explain why (or if) depreciation rates should still be harmonized.

Exhibit 5

Issue E: Cost of Capital

5-VECC-58

Reference – Exhibit 5, Tab 3, Schedule 1

- a) What precipitated the request to Concentric to study the issue of capital structure?
- b) Please provide all correspondence, emails, presentations that occurred between EGI and its corporate parent with respect to the change in capital structure.
- c) Other than the Concentric Report what evidence is EGI relying upon that would suggest recent events (or otherwise) would suggest a need to change capital structure.
- d) Please provide any public market based research which suggests that without a change in its capital structure EGI or its parent would suffer a downgrade of its debt capital.

5-VECC-59

Reference – Exhibit 5, Tab 3, Schedule 1

- a) Were any other studies commissioned by EGI, its parent owner or any of its affiliates (including by its legal agents) with respect to changing EGI's capital structure?
- b) If yes please provide those reports.

5-VECC-60

Reference – Exhibit 5, Tab 3, Schedule 1, Attachment 1 - Concentric

- a) Please provide a list of all natural gas utilities Concentric has studied which apply a fixed charge to recover 100% of its gas delivery charge to residential customers. Please provide the year in which the utility changed to a fully fixed rate.
- b) For the above list of utilities please provide the any credit ratings that were made prior to and after moving to a 100% fixed rate.

Exhibit 6

Issues F. Revenue Deficiency

6-VECC-61

Reference – Exhibit 6, Tab 1, Schedule 1

- a) Please update Table 1 to show 2022 actual results.

Exhibit 7

Issues G. Cost Allocation

7-VECC-62

Reference – Exhibit 7, Tab 1, Schedule 1, 3

The EGD and Union cost allocation studies were underpinned with customer information, system operations detail, and financial data from different IT systems. At times, Enbridge Gas was limited in proposing cost allocation methodologies based on information that was common and available for the amalgamated utility

The Company was not able to recreate two stand-alone cost allocation studies for the EGD and Union rate zones in the same format that was approved in EGD's and Union's respective 2013 Cost of Service proceedings.

- a) Given that the data appears to be from two separate IT systems please provide specific reasons why the prior approved cost allocation methodologies/ studies for EGD and Union could not be used to determine 2024 rates.
- b) Please provide the last utilized excel models that were used for last Board approved EGD and Union rate zone cost allocations.

7-VECC-63

Reference – Exhibit 7,

The rate zone harmonization allocates the costs of the transmission system facilities across all in-franchise customers, regardless of geographic location.

- a) If the Board were to decide that EGI should create rate zones aligned with NAESB trading windows -i.e., North (GMIT NDA, Union EDA, Union NCDA) South-Central (Enbridge CDA, Union CDA, Parkway CDA) and Eastern (Enbridge EDA KPUC/Union EDA) - what type of adjustments would need to be made to the cost allocation study to accommodate this type of rate zone structure? Specifically address how such “supply based” rate zone might change gas supply, storage and transmission allocations.
- b) If the Board were to approve the proposed cost allocation methodologies does this a single rate zone/harmonized rates? Would it remain fair and reasonable to over the long run apply the proposed cost allocation methodologies to the existing multiple rate zone rate design?

7-VECC-64

Reference – Exhibit 7, Tab 1, Schedule 4

The Panhandle System and St. Clair System are westerly peaking systems serving in-franchise demands on design day.

- a) Does gas ever physically flow westerly on either the Panhandle or St. Clair System?

7-VECC-65

Reference – Exhibit 7,

- b) Please provide all the live excel models that are used in the cost allocation outputs shown in attachments to Schedule 1

Exhibit 8

Issue H. Rate Design

8-VECC-66

Reference – Exhibit 8, Tab 2, Schedule 2

- a) If the Board rejects EGI's proposal for harmonized rate classes would the Utility still implement its proposed common commodity charge for sales service customers?
- b) If the Board were to order EGI to create rate zones related to EDAs or other supply transactions zones would a harmonized commodity charge still be warranted?

8-VECC-67

Reference – Exhibit 8, Tab 2, Schedule 2 / Exhibit 4, Tab 2, Schedule 2, Tables 1&2

The proposed rate design incorporates the market prices at all of the various supply locations in the gas supply portfolio whereas the current approved gas supply commodity charge for each rate zone is based on a single source of supply (Empress, Alberta Border, or Dawn).

For the Union North West rate zone, the proposed increase is driven by a weighted average reference price that is greater than the Empress price. This increase is offset by a reduction in transportation rates that results from the proposal for one rate zone.

- a) The April 2022 QRAM show an almost 30% difference between the EGD and Union North West reference prices (Ex 4). Why is not a better reflection of cost causality to create commodity charges that are best reflective of the gas purchased for those customers? For example, if sales customers in the current Union North West Zone purchase gas exclusively from the Western Sedimentary Basin, why is some form of Alberta reference price not better reflective of their gas costs than a harmonized approach?

Exhibit 9

Issues I: Deferral and Variance Accounts

9-VECC-68

Reference – Exhibit 9, Tab 1, Schedule 2

- a) For each the Enbridge Transactional Service Account 179-80 and the Union Upstream Transportation Optimization Account 179-131, please provide the year-end balance in each account (shown separately) for the years 2019 through 2022. Please include a column showing the amount of benefit or payment to ratepayers for each year.
- b) Has EGI given any consideration to changing the 90/10 sharing mechanism in order to provide greater incentives to seek out optimization revenues?
- c) Please confirm (or correct) that the harmonized proposed account will capture variances on an asymmetrical basis (i.e., only excess revenues are captured not shortfalls from the \$15.3 million credit included in rates).

9-VECC-69

Reference – Exhibit 9, Tab 1, Schedule 2

- a) For the period 2019 through 2022 please provide a table showing the year-end annual EFG balances separately for the Enbridge and Union (prior to application of deadband rate zones). Please also provide the amount ultimately recovered (or paid) for that year's balance.

9-VECC-70

Reference – Exhibit 9, Tab 1, Schedule 2

- a) Which class of customer are balances in the new proposed Unauthorized Overrun Non-Compliance Account 179-304 disposed to?

9-VECC-71

Reference – Exhibit 9, Tab 1, Schedule 2

- a) EGI proposes harmonized accounts for GDAR (179-301) and ICM (179-306). It is unclear to us how the anticipatory establishment of these accounts meets the Board's materiality threshold and for GDAR the requirement to be costs that are beyond management's control. Please elucidate.
- b) What is the disadvantage of seeking to establish these accounts if and when they are required and if EGI can show at that time they meet the Board's requirements for establishment of a variance or deferral account.
- c) If these accounts are established does that, in EGI's view, establish the ability to book amounts in these accounts without explicit prior approval of the Board?

9-VECC-72

Reference – Exhibit 9, Tab 1, Schedule 3, page 7 / EB-2015-0200 Decision and Order Settlement Agreement page 23

"Enbridge Gas proposes to refund through the DPSCDA any revenue generated from the sale of the surplus capacity up to the 89 TJ/d per year. Based on the 2023 Rate M12 Dawn to Parkway demand rate, the maximum annual revenue that could be realized from the sale of the long-term firm surplus capacity is approximately \$4 million⁴ per year."

"..\$1.34 million is the maximum annual revenue that could be realized from the sale of long-term firm surplus capacity effective November 1, 2017 (30,393 GJ/d x \$0.121/GJ/d x 365 days)." EB-2015-0200

- a) The second reference shows that the original credit was based on a \$0.121/GJ/d figure. Please provide the equivalent figure for the proposed account and explain how it is derived.
- b) Please explain why the reasons for the approximate 30% increase in the surplus capacity from the 2017/2018 projections made in EB-2015-0200.

9-VECC-73

Reference – Exhibit 9, Tab 1, Schedule 3, page 15/ Exhibit 2, Tab 6, Schedule 2, pages 87-118 / Exhibit 1, Tab 13

“There are no expenses related to the program included in the 2024 Test Year Forecast. Any amounts recorded in the Enhanced DIMP Deferral Account will reflect the costs incurred to administer, implement, and execute the program.”

Reliability modelling: One of the major hazards to steel mains is corrosion. A reliability model accounting for pipe attributes has been developed through the Asset Health Review (AHR) operating process under DIMP to forecast the number of corrosion leaks based on statistical analysis of corrosion leak history

“..Condition-based drivers are monitored through existing activities of the DIMP, as well as the Leak and Corrosion Survey programs.”

- a) The evidence in the AMP in Exhibit 2 is that EGI has recently developed DIMP modeling and other activities related to DIMP. Please explain how these programs differ from the DIMP costs that are anticipated to be captured in the proposed deferral account.
- b) Please provide the budget, business plan and plan horizon which underpins the “approximately \$10 million in DIMP costs that might be captured in this account.
- c) Other than its reference to the Board’s recommendation that EGI consider small main testing what characteristics or elements differentiate this program from any other ongoing capital maintenance program like TIMP and that would require separate accounting treatment.
- d) Is it EGI’s position that the DIMP is only been undertaken at the behest of the suggestion made by the Board in EB-2020-0293?
- e) What are the annual capital and operating costs of the TIMP in 2022?

END OF DOCUMENT