February 10, 2023

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VIA RESS

Ms. Nancy Marconi
Registrar
ONTARIO ENERGY BOARD
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Marconi:

Re: EB-2022-0200 – Enbridge Gas Inc. (EGI) Application for 2024 Cost of Service Rates.

Industrial Gas Users Association (IGUA) Phase 1 Interrogatories for EGI.

Attached please find IGUA's Phase 1 interrogatories for EGI in the captioned proceeding.

On the topic of cost allocation, we have deferred to Phase 2 questions regarding *"methodologies and judgements used and the proposed application of that study"*[1] to the design and derivation of proposed harmonized rates. We note that the formulation of the Phase 1 cost allocation issue (24) on the OEB approved issues list and the formulation of the Phase 2 cost allocation issue (55) on the approved issues list are somewhat different. We have nonetheless proceeded on the acknowledgement by EGI through external counsel that cost allocation questions in Phase 2 as outlined above will be entertained by EGI.

Yours truly,

Ian A. Mondrow

c: S. Rahbar (IGUA)
V. Innis (EGI)
D. Stevens (Aird & Berlis LLP)
D. O'Leary (Aird & Berlis LLP)
K. Viraney (OEB Staff)
Intervenors of Record

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[1] Issues List, Issue 24.

ONTARIO ENERGY BOARD

Enbridge Gas Inc.

Application to change its natural gas rates and other charges beginning January 1, 2024

PHASE 1 INTERROGATORIES to ENBRIDGE GAS INC.

from

INDUSTRIAL GAS USERS ASSOCIATION (IGUA)

1.1-IGUA-1

Preamble:

In support of its application and proposed revenue requirement recovery from customers, EGI has retained, and presented evidence from, a number of external experts.

Questions:

(a) Please provide EGI's best estimate of the total cost for all of the external experts retained by EGI in support of its application.

(b) Please provide the total OEB proceeding related regulatory costs included in EGI's 2024 test year revenue requirement.

1.6-IGUA-2

Preamble:

In Exhibit 1, Tab 6, EGI reviews its customer engagement process undertaken in support of this application. In this evidence EGI describes meetings directly with contract customers. At paragraph 28 EGI discusses *"[p]reviously identified concerns related to customer engagement, such as the ability for customers to review the cumulative impact of their choices on overall rates"* and how those concerns were addressed. EGI also indicates elsewhere in its evidence that it has assessed the impact of its rate harmonization proposals on each of its large volume contract customers.

Question:

Please confirm that, as of the date of submission of these interrogatories, large volume industrial customers have not been provided with information on the specific impact of EGI's application proposals on their individual annual EGI bills.

1.13-IGUA-3

Preamble: Exhibit 1, Tab 13, Schedule 3.

At page 1, paragraph 2, EGI explains that its proposed Enhanced Distribution Integrity Management Program (Enhanced DIMP) is in response to the OEB's Decision in the St. Laurent Ottawa North Replacement Project application (EB-2020-0293). The full quote from the decision part of which is cited by EGI at paragraph 2 is as follows (emphasis added to the portion of paragraph not cited by EGI in its evidence in this application):

> *For the reasons provided in this Decision and Order, the OEB denies Enbridge Gas's leave to construct application. The OEB finds that the need for the Project and the alternatives to the Project have not been appropriately assessed. Enbridge Gas has not demonstrated that the pipeline integrity is compromised, and that pipeline replacement is required at this time. The OEB urges Enbridge Gas to thoroughly examine other alternatives such as the development and implementation of an in-line inspection and maintenance program using available modern technology, and propose appropriate action based on its finding as part of its next rebasing application.*

At page 6, paragraphs 18-20 of the referenced evidence EGI explains that $10 million in forecast annual costs of the Enhanced DIMP are not included in forecast 2024 rates and are proposed to be recorded for recovery through a new proposed deferral account.

Questions:

(a) Why did EGI not include the forecast costs of the Enhanced DIMP in forecast 2024 rates, like all other integrity management costs?

(b) The direction cited by EGI in support of its proposed Enhanced DIMP was St. Laurent pipeline specific. Are there other statements made by the Hearing Panel in the St. Laurent case which EGI relies on in advancing its Enhanced DIMP proposal?

(c) EGI asserts that the Enhanced DIMP *"responds to the OEB's Decision in the St. Laurent Ottawa North Replacement Project Decision, and is above and beyond he requirements set out in the code as well as industry best practices"*. (Page 6, paragraph 13 of the cited evidence.) Does EGI believe that the Enhanced DIMP is necessary (apart from the direction that EGI says the OEB provided)?

2.1-IGUA-4

Preamble:

We would like to identify and understand the particular gas supply plan related costs which impact contract rate customers.

Question:

Please list all categories of gas supply costs that are allocated to delivery rates and shared by EGI's contract customers, by customer service type (i.e. T-service, bundled, unbundled, etc.) and associated rate class(es).

4.2-IGUA-5

Preamble:

In respect of EGI's proposal to move to a common gas commodity reference price for inclusion in the gas cost components of 2024 revenue requirement (including, in respect of delivery rates, gas in storage forming part of rate base, UFG, company use gas and compressor fuel), the evidence reviews the advantages of the proposed use of the weighted average of EGI's forecast commodity costs across its gas supply portfolio. These advantages include providing a sales service only price for gas and ensuring a prospective gas commodity cost recovery variance of zero.

Question:

Are there any disadvantages, relative to current practices, to moving to the proposed common reference price?

4.7-IGUA-6

Preamble: Exhibit 4, Tab 7, Schedule 1, Attachment 1, paragraph 7.

EGI states:

The priority for utilizing excess Dawn Parkway System capacity is to serve long-term demands.

Question:

Please explain the rationale for this priority.

4.7-IGUA-7

Preamble: Exhibit 4, Tab 7, Schedule 1, Attachment 1, paragraphs 8-9.

EGI explains the proposed approach to allocation to delivery customers of available capacity to reduce the PDO.

Questions:

(a) Please confirm that customers holding M12 Dawn to Parkway capacity to meet their PDO and customers not holding M12 Dawn to Parkway capacity to meet their PDO are treated the same in EGI's proposed capacity allocation methodology.

(b) If not confirmed, please explain the differences in treatment proposed based on whether or not the customer holds M12 Dawn to Parkway capacity.

5.2-IGUA-8

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 31.

The cited evidence indicates:

Beginning in 2021, Enbridge's executive and staff compensation is tied to the Company's progress towards its emission targets.

Questions:

(a) Please explain what emissions targets are referred to in the cited evidence (i.e. legislated, corporate, both and/or other).

(b) Please provide details of how compensation costs included in proposed 2024 rates are tied to progress by EGI or Enbridge Inc. towards emission targets.

(c) To the extent not provided in response to part b., please provide any further details of how compensation to those with responsibilities which include regulated Ontario gas distribution operations is tied to progress towards the emission targets included in response to part a.

4.5-IGUA-9

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 4-3.

The following table summarizes the applied for amortization accounts included in the Concentric report.

Account	Title	Investment	Recommended Amortization Period in Years
474.00	Regulators	$488,870,931	25
475.00	Mains Envision	$181,264,676	25
483.00	Office Furniture and Equipment	$29,776,062	15
486.00	Tools and Work Equipment	$79,966,854	15
487.70	Rental - NGV Appl	$864,755	15
487.80	Rental – NGV Stations	$7,774,175	20
488.00	Communication Structures and Equipment	$11,224,609	10
490.00	Computer Equipment	$30,306,679	4
490.30	Computer Equipment – WAMS	$4,680,899	10
491.01	Software Acquired Intangibles	$155,164,785	4
491.02	Software Developed Intangibles	$38,776,288	4
491.03	CIS Acquired Software	$87,626,214	10
491.04	WAMS	$85,221,905	10

Questions:

(a) Please provide an explanation for each of the recommended amortization periods listed above, including a comparison to any available peer data.

(b) Please confirm that for assets such as computers and software, Concentric is recommending new asset classes post-2023 with new rates. If not confirmed, please explain.

(c) Further to the response to (b), please calculate the revised depreciation expense if the 2023 amortization rates for the asset classes were not adopted and instead the costs were amortized using the previously approved rates.

(d) Please provide empirical evidence from EGI that an amortization period of 4-years is a reasonable period of time for computer equipment and software.

(e) Regarding computer equipment and software, please provide a listing of all major assets included in the accounts, the expected useful life for the assets, and the basis upon which the expected useful life has been determined (i.e., contractual agreements, management best estimate, past experience, etc.).

4.5-IGUA-10

Preamble: Exhibit 4, Tab 5, Schedule 1, pages 7 and 8, paragraph 18.

At paragraph 18, Enbridge Gas states:

"Concentric recommended the use of a credit adjusted risk-free (CARF) rate as an appropriate discount rate on the basis that the CARF is consistent with discount rates mandated by accounting standards for asset retirement obligations for financial statement disclosures and estimating the discount rate in securitization calculations. The CARF is also aligned with other pipelines in similar applications to the Canadian Energy Regulator (CER). Enbridge Gas's CARF was 3.78% at the time the substantive work on the depreciation study was performed, which approximates the discount rate of 3.75% used by Concentric."

Questions:

(a) Please provide a summary of all jurisdictions studied by Concentric, and in particular by Mr. Kennedy, where the CDNS method for recovering net salvage costs is used or has been used. Please also provide a brief history of the use of CDNS in the jurisdiction including any relevant facts regarding its implementation or discontinuation as applicable.

(b) For each jurisdiction included in response to (a), please provide the current discount rate used to calculate net salvage under CDNS, if available, the historical discount rate used if CDNS is not currently used, and the discount rate recommended by Concentric. For each discount rate provided please also provide the stated rationale for the discount rate. For example, whether the rate was reflective of a credit adjusted risk-free or some other basis, as well as whether the rate is the approved or applied for rate.

(c) Please provide reference to the US GAAP standard, and a copy of the specific codified guidance, that requires the use of a credit adjusted risk-free rate as the discount rate in a CDNS calculation. Please provide the same information for asset retirement obligation calculations.

(d) Please confirm that the calculation of net salvage collected under CDNS is not equivalent to an asset retirement obligation calculation under US GAAP. If not confirmed, please fully explain and provide in an working Excel file illustrative calculations demonstrating how both calculations are equivalent.

4.5-IGUA-11

Preamble: Exhibit 4, Tab 5, Schedule 1, pages 9 to 15.

Enbridge Gas reports several reclassifications of assets between USA accounts. The IGUA requests further details on the impact of the reclassifications on depreciation and net salvage.

Question:

Please prepare a working Excel schedule that separately reports the impact of each transfer on the forecast depreciation and net salvage costs for each account. Please prepare the calculations using both the applied for rates in one Excel file and the previously approved rates in the second file.

4.5-IGUA-12

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 3-3.

Concentric provides an example in a table comparing the ELG and ALG procedure, and concludes:

First, using the ALG procedure, after the first 5 years, no depreciation has been collected for the asset remaining in service. Essentially, the concept of depreciation expense matching the assets providing service is not met.

Questions:

(a) Please confirm that the example may not properly reflect the results of a mass property account where a significant portion of a vintage of assets are retired at or after the average service life, and over a relatively short period of time. For example, if 95% of the vintage of assets are retired at approximately year 50, does Concentric agree that the difference under ELG and ALG would be less significant. If not confirmed, please explain.

(b) Notwithstanding the simplified example provided by Concentric, does Concentric agree that while $1,000 of accumulated depreciation is removed under the ALG example in year 5, from an accounting perspective both assets were charged $100 of depreciation per year (i.e, $500 in total up to year 5), as opposed to just one asset being charged $1,000 of depreciation expense? For example, the asset that was retired would have in theory been charged $500 of depreciation expense ($100 per year) and would have negative accumulated depreciation of $500 with the retirement of $1,000 in year 5, whereas the second asset would also have $500 of depreciation accumulated. If not confirmed, please reconcile the above with the required accounting entries to record mass property depreciation under US GAAP and best practices for regulated utilities.

(c) Please confirm that the determination of depreciation under either ELG or ALG is an estimate. If not confirmed, please explain.

(d) Please confirm that Concentric expects that future updates to the estimated lives of at least some of the asset classes will be required whether an ELG or ALG procedure is applied. If not confirmed, please explain.

(e) Please confirm that adoption of the ELG procedure will increase the depreciation expense for EGI, all else being equal. If not confirmed, please explain.

(f) Concentric has advised that EGI continues to consider the adoption of modified depreciation expense in the future to reflect an economic depreciation expense based on

an economic planning horizon. Adoption of an economic planning horizon approach will truncate the lives of the assets and further increase depreciation expense as Concentric's calculations demonstrate. EGI is applying to increase depreciation expense by $193.9 million in 2024. Please quantify the portion of this increase that is related to the change from the ALG and generation arrangement procedures to ELG. Please also provide the detailed calculations in Excel showing the derivation of the change on an account-by-account basis.

4.5-IGUA-13

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 3-10.

Concentric discusses four alternatives to address the collection of salvage costs.

Questions:

(a) Please prepare a schedule (in a working Excel file) that provides the last ten years of negative net salvage collected by EGD and Union, as well as the last 10 years of actual salvage costs incurred (i.e., 2013 to 2022).

(b) Please also provide a schedule showing the build up of the accumulated net salvage balance using the opening balance at the beginning of the 10-year period for each entity.

(c) Please provide a forecast of the net salvage to be collected and the salvage costs forecast to be incurred for the next 10 years (i.e., 2023 to 2032).

4.5-IGUA-14

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 3-12.

Concentric states that for the CDNS calculation it first calculates the historic indications of salvage costs, then escalates these costs at a rate of 2% to the future date the costs are incurred and finally discounts the costs back at an assumed credit adjusted risk-free rate of 3.75%.

Questions:

(a) Please provide a working Excel model that calculates the CDNS recommended salvage rate for each account. Please ensure that all support related to the determination of the 2% inflation and the credit adjusted risk-free rate are included in the model and that a change to one of the parameters provides for an update of both the CDNS salvage rate and the forecast costs by account.

(b) For each account, please summarize all adjustments made by Concentric to the historic indications of salvage costs that were in addition to applying an escalation rate to the historical costs. Additionally, please explain what escalation rates were applied to the costs, and why those rates are reasonable.

(c) Further to the response to (b), if available, please provide the derivation of the historic indications of salvage costs for each account in a working Excel file showing both the escalation of costs and any adjustments made to reflect current indications of costs.

4.5-IGUA-15

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, Section 6.

Questions:

(a) For all accounts included in Section 6, please provide revised Iowa curves that reflect the actual retirement experience, the recommended curve, the historically approved curves for each of EGD and Union Gas, if different, and all other Iowa curves studied by Concentric, including the residual measure of each of those curves.

(b) Please provide an illustrative calculation in a working Excel file for Account 466 demonstrating how Concentric has calculated its residual measures as between the reported retirements and the retirement curve for each of the curves studied. Please also outline any judgment applied by Concentric to its calculations or formulas used in the analysis and determination of residual measures.

(c) For each account, please provide the information included in each "Retirement Rate Analysis", for example at page 6-72, in an Excel file, including the age at the beginning of the interval, exposures at beginning of age interval, retirement during age interval, retirement ratio, survivor ratio, and % surviving. Please include a separate tab for each account.

4.5-IGUA-16

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 3-15.

Concentric states for Account 466 that Canadian gas distribution utility peers have a range of lives between 35 and 37 years. Concentric recommends a 30-R4 curve (as compared to 30-S3 previously approved) for Account 466 which has a residual measure of 3.3601.

Questions:

(a) Please provide revised Iowa curves and residual measures for Account 466 using the following curves:

(i) Iowa 35-R4.

(ii) Iowa 37-R4.

(iii) Iowa 40-R4.

(b) Please calculate, using the ELG and ALG procedures, the impact on depreciation and net salvage of the above changes in Iowa curve and provide all supporting calculations.

(c) From a review of observed retirement data on page 6-58, it appears that the compressor equipment has a significantly longer average service life than Concentric estimates. For example, approximately 80% of the investment is surviving beyond age 45. Please explain in detail the underlying characteristics of this account that are leading to the resulting retirement pattern and why, based on this information, the recommended survivor curve is reasonable as compared to a longer life curve. For example, please explain in detail what assets are included, why the observed life characteristics are occurring and why the results should be considered reasonable.

(d) Please comment on whether the compressor equipment undergoes routine maintenance over time to extend the useful life of the assets or whether the compressor equipment generally is replaced after a fixed period of time with or without replacement. Please reconcile this discussion with the observed retirement pattern on page 6-58.

Please provide a detailed explanation of the characteristics of the assets in this account, the approach to maintenance, expected operational lives, and other considerations that are relevant to the useful life of the physical assets. Please also describe the normal life cycle of the assets, including any maintenance or refurbishment.

4.5-IGUA-17

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 2.

Concentric is proposing an increase in depreciation related to account 472.35 of $8.9 million, with a proposed rate of 50.48% compared to the current rate of 2.32%. Concentric also reports that there is a truncation date (page 5-2) of 2023 for the Mainway assets.

Questions:

(a) Please provide a further explanation for the truncation of these assets in 2023. Please advise when it became known to EGI that the life of the assets would be truncated in 2023. Further, please provide any evidence from the previous depreciation study that supports the previously used lives.

(b) If available, please provide the historical retirement data for this account.

(c) The surviving original cost for these assets in December 31, 2021 (Page 5-2) was $15.9 million. The calculated accrual appears to result in a true up of depreciation in 2024. Please provide a schedule showing the actual depreciation charged to account 472.35 historically, as well as the forecast depreciation to be claimed.

(d) For account 482.04 the truncation date was 2022 and that there was no further depreciation forecast in 2024. Given this approach, please fully explain why a truncation of 2023, would result in forecast depreciation in 2024 for account 472.35, whereas a truncation of 2022 does not.

(e) Please provide the actual retirement date for the assets, and explain whether the assets have been retired. If the assets have not been retired, please explain when the assets will be retired.

4.5-IGUA-18

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 3-17 and 3-18.

Concentric is proposing an increase in depreciation related to account 473.01 of $48.1 million, with a proposed rate of 3.63% compared to the current rate of 2.27% for EGD and 3.02% for Union. No peer analysis appears to have been considered and the selected curve results in a worse residual measure than other alternatives.

Questions:

(a) Please provide revised Iowa curves and residual measures for Account 473.01 using the following curves:

(i) Iowa 45-L1.0.

(ii) Iowa 45-L0.5.

(iii) Iowa 50-L1.0.

(iv) Iowa 50-L0.5.

(b) Please calculate, using the EGL and ALG procedures, the impact on depreciation and net salvage of the above changes in Iowa curve and provide all supporting calculations.

(c) From a review of retirement data on page 6-71, it appears that the assets in this account have an unusual life with rapid retirements through age 40.5 and then a stabilization of retirements thereafter with another increase in retirements after approximately age 60.5. Please explain in detail the underlying characteristics of this account that are leading to the resulting retirement pattern and why, based on this information, the recommended survivor curve is reasonable as compared to a longer life curve. For example, please explain in detail what assets are included, why the observed life characteristics are occurring and why the results are considered reasonable.

(d) Please provide a detailed explanation of the characteristics of the assets in this account, the approach to maintenance, expected operational lives, and other considerations that are relevant to the useful life of the physical assets. Please also describe the normal life cycle of the assets, including any maintenance or refurbishment.

(e) Please comment on whether the assets in this account undergo routine maintenance over time to extend the useful life of the assets or whether the assets are generally replaced after a fixed period of time with or without replacement. Please reconcile this discussion with the observed staged retirement pattern on page 6-71.

(f) Given the long apparent life of the assets in this account, has Concentric attempted to model an O curve (i.e., an O4 curve) against the observed retirement data. If not, why not?

(g) Please provide the curve fit for this account that results in the best residual measure for the observed retirement data both through age 50.5 and through the entirety of the observed data. If the result is achieved by two different curves, please provide both. Please also provide the Iowa curve and the calculated depreciation expense (including net salvage), using each curve.

4.5-IGUA-19

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 3-18 and 3-19.

For Account 474 - regulators - Concentric is proposing an increase in the depreciation rate to 8.86% (from 5.00%) despite no collection of net salvage and a proposed extension of the life from 20-SQ to 25-SQ.

Questions:

(a) Please provide a detailed calculation of the 8.86% depreciation rate and reconcile this rate with the previously approved rate of 5.00% for Union under the generation arrangement procedure.

(b) Concentric states the "investment in this account is more heavily weighted towards the historic Union assets" but it is noted in Attachment 2 that $315.9 million of the historical investment was in EGD and only $192.5 million is in Union. Please reconcile this information with Concentric's statement.

(c) No Iowa curve was provided for the assets in Account 474. Please fully explain why this is the case and if retirement data exists, please provide the previously approved and applied for Iowa curves mapped against that data.

(d) Please provide a detailed explanation of the characteristics of the assets in this account, the approach to maintenance, expected operational lives, and other considerations that are relevant to the useful life of the physical assets. Please describe the normal life cycle of the assets, including any maintenance or refurbishment.

4.5-IGUA-20

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 3-19.

Concentric states for Account 475.21 that Canadian peers have a range of lives between 55 and 80 years. Concentric recommends a 55-R3 curve (as compared to 61-R3 previously approved for EGD or other curves) for Account 475.21. The calculated residual measure for the 55-R3 curve is inferior to other residual measures.

Questions:

(a) Please provide revised Iowa curves and residual measures for Account 475.21 using the following curves:

(i) Iowa 60-R3.

(ii) Iowa 61-R3.

(iii) Iowa 70-R3.

(iv) Iowa 80-R3

(b) Please calculate, using the ELG and ALG procedures, the impact on depreciation and net salvage of the above changes in Iowa curve and provide all supporting calculations.

(c) Has Concentric modeled whether an R2 or R2.5 curve may have a better visual fit to the observed retirement data through age 40.5? If not, why not. Please provide a revised Iowa curve and residual measure using a 60-R2 and 60-R2.5 curve. Further, please provide the same information for a 65 and 70 year life.

(d) From a review of retirement data on page 6-83, it appears that there is a relatively consistent retirement of assets at each age, as depicted by the actual retirement pattern. However, a significant portion of the assets continues to survive well beyond the average life. Please explain in detail the underlying characteristics of this account that are leading to the resulting retirement pattern and why, based on this information, the recommended survivor curve is reasonable as compared to a longer life curve. For example, please explain in detail what assets are included, why the observed life characteristics are occurring and why the results are considered reasonable.

(e) Please provide a detailed explanation of the characteristics of the assets in this account, the approach to maintenance, expected operational lives, and other considerations that are relevant to the useful life of the physical assets. Please also describe the normal life cycle of the assets, including any maintenance or refurbishment.

4.5-IGUA-21

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 3-20.

Concentric is proposing an increase in the depreciation rate related to account 475.3 to 2.72% from 1.85% (EGD) and 2.35% (Union). The increase occurs despite holding net salvage largely unchanged, and results in a $27.0 million increase in the depreciation provision per Attachment 2. The proposed 60-R4 Iowa curve is also on the low end of the peer range of 60-80 years for this asset class, and has a higher residual measure than other curves.

Questions:

(a) Please provide revised Iowa curves and residual measures for Account 475.3 using the following curves:

(i) Iowa 65-R3.5.

(ii) Iowa 65-R3.0.

(iii) Iowa 65-R4.0.

(iv) Iowa 70-R2.0

(b) Please calculate, using the ELG and ALG procedures, the impact on depreciation and net salvage of the above changes in Iowa curve and provide all supporting calculations.

(c) Please provide a detailed explanation of the characteristics of the assets in this account, the approach to maintenance, expected operational lives, and other considerations that are relevant to the useful life of the physical assets. Please also describe the normal life cycle of the assets, including any maintenance or refurbishment.

4.5-IGUA-22

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, pages 3-21.

For Account 478, Concentric recommends a 15-S2.5 curve, which does not appear to fit the retirement data well either visually or mathematically as per page 6-100. Further, Concentric's evidence refers to a potential advanced metering infrastructure program as apparent support for the recommended life.

Question:

(a) Please confirm that the average life of the meters based on the retirement data occurs at approximately age 27.5 to 28.5. If not confirmed, please explain.

(b) Has Concentric considered using an amortization account for these assets as opposed to the 15-S2.5 curve? Please fully explain why an amortization account would not be appropriate.

(c) Please calculate the impact on depreciation and net salvage costs of using a 30 year amortization account for Account 478 as opposed to the 15-S2.5 curve recommended by Concentric.

(d) Please provide a detailed explanation of the characteristics of the assets in this account, the approach to maintenance, expected operational lives, and other considerations that are relevant to the useful life of the physical assets. Please also describe the normal life cycle of the assets, including any maintenance or refurbishment.

(e) Please further expand on the relevance of an advanced metering initiative for this account, and why that initiative would impact the lives of the assets in this account.

4.5-IGUA-23

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, Section 7, pages 7-20 and 7-21.

The IGUA observes that several of the accounts have a high negative salvage percentage relative to the applied for net salvage rate. As an example, Accounts 473.01 and 473.02

have observed negative net salvage rates of -69.02% and -167.51%, respectively. Concentric has recommended a -32% and -26% net salvage rate for these accounts, respectively.

Question:

(a) Please reconcile the recommended net salvage rates with the observed net salvage rates for each of the accounts studied by Concentric, and explain the reason for the selected net salvage rates. Please separately detail any adjustments to the salvage rates caused by the CDNS method and any other judgment applied by Concentric in the selection of the salvage rate that is not already provided in Section 3, if any.

(b) Please confirm that if Concentric were to apply the net salvage rates included at pages 7-20 and 7-21 for the above referenced accounts, that the calculated net salvage costs would increase significantly. If not confirmed, please explain.

(c) Having regard to the magnitude of some of the negative net salvage rates calculated by Concentric using historical data, please comment on the potential size of any unfunded net salvage liability that may exist if there is an understatement in the amount of forecast net salvage costs that will ultimately be incurred. If Concentric can quantify the potential size of the unfunded salvage costs, please provide that amount including support for the calculation.

4.5-IGUA-24

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, Section 8.

To confirm certain of Concentric's calculations and develop alternative estimates of depreciation expense requires the information provided in Section 8 in an Excel format.

Questions:

(a) Please provide the information included in Section 8 for each account within a working Excel spreadsheet, with a separate tab for each account. Where possible, please leave in place all calculations that can be performed using the data included. (For example, the accumulated depreciation factor of 0.45 on Page 8-3 is calculated simply by taking the allocated actual booked amount divided by the original cost, the composite annual accrual rate of 1.69% is calculated by dividing the annual accrual by the original cost, etc.)

(b) If a specific amount cannot be calculated using the information in Section 8, please explain how Concentric derived the amount and provide the source of the information necessary to replicate the calculations.

4.5-IGUA-25

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachments 2 and 3.

Some of the information contained in the Excel versions of Attachments 2 and 3 is hard coded. It would be of benefit to have similar information from different perspectives, including with net salvage and other adjustments separately identified. Attempts to insert formulas to calculate the amounts included in the above attachments but observed some unexplained differences. For example, when calculating the provision in Attachment 2 using proposed rates, there are consistently differences.

Questions:

(a) Please refile copies of both attachments with working formulas and if any changes or errors exist, please identify those amounts. Additionally, if the hard coded information is derived in some other manner, please isolate the differences and explain how the amounts are calculated. For example, if the difference relates to the amortization of reserve differences, please show this amount as a further separate adjustment and calculation in the Excel file. For Attachment 3, please include the account number with each calculation.

(b) Please expand Attachment 2 to break out the current and proposed rates by the depreciation (i.e., life component) and net salvage components, and provide the differences by account for each component. If any other amortization of reserve differences exists, please also separately break out those amounts.

(c) Please revise Attachment 2 to calculate the proposed rates using the ALG procedure, providing all supporting calculations, with the current and proposed rates broken down by depreciation (i.e. life component) and net salvage components. Please use the curves as applied for but applying the ALG procedure rather than the ELG procedure.

4.5-IGUA-26

Preamble: Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 3-14.

Concentric frequently refers to a peer analysis that it has completed for both lives and net salvage rates, but the analysis does not appear to be filed.

Questions:

(a) Please provide a copy of the peer analysis in a working Excel file for both lives and net salvage or refer to where the information is included in the record for each account studied.

(b) If the peer analysis is not included in the Concentric report, please fully explain why the evidence was not included as part of the original filing. For example, if not filed, does Concentric consider the peer analysis to be of less relevance or weight to Concentric's conclusions and recommendations? Please explain.

(c) Please explain in detail why each of the peers included in Concentric's analysis are relevant peers that should be compared to the EGI assets. Similarly, if any possible peers in the Canadian utility industry were excluded, please fully explain why this was the case.

(d) For each of the companies included in the peer analysis, please also provide a separate table showing the life or net salvage rate recommended by Concentric for the peer, if Concentric performed the depreciation and net salvage study.

5.3-IGUA-27

Preamble: Exhibit 5, Tab 3, Schedule 1, Page 2, Paragraph 5

The cited evidence states:

Based on the increased risk profile of Enbridge Gas, Concentric recommends that the OEB approve an increase to the deemed equity ratio for Enbridge Gas from 36% to 42% to maintain financial strength and continued access to capital at a reasonable cost, and to manage the Energy Transition under a variety of economic and capital market conditions. As Concentric notes in the Study: "Our recommended equity ratio for Enbridge Gas in the upcoming rate setting period is consistent with the results of our analysis, which indicate that an increase in equity thickness is warranted. This is particularly important as the Company will need to maintain financial strength to continue accessing the debt and equity capital it needs to manage the Energy Transition under a variety of economic and capital market conditions, while providing safe and reliable service to its customers."

Questions:

(a) What in particular are the *"variety of economic and capital market conditions"* referred to in the cited passage?

(b) Has Concentric or EGI (and in the case of EGI either directly, through a consultant or as part of any industry association) or any affiliate of EGI (either directly, through a consultant or as part of any industry association) quantified 1) *"the debt and equity capital [EGI] needs to manage the Energy Transition"* and/or 2) the parameters measuring the requisite *"financial strength"* that EGI will need to maintain?

(c) Please provide the results of the analyses referred to in response to part (b). Please provide copies of any spreadsheets (with working formulas and links) used to conduct the analysis.

5.3-IGUA-28

Preamble: **Exhibit 5, Tab 3, Schedule 1, Attachment 1**

Question:

Please provide copies of, or a working web link to, each of the documents cited in the footnotes contained in the Concentric report, other than (1) documents produced and published by the Ontario Energy Board and (2) documents for which an accurate and up to date web link is provided in the subject footnote.

5.3-IGUA-29

Preamble:

Exhibit 5, Tab 3, Schedule 1, page 1, paragraph 3

Enbridge Gas believes that significant changes in the environment in which it operates have occurred since the time of the 2013 Rates proceedings.

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 17 of 164, 2nd paragraph

Concentric's analysis begins with an assessment of how the Company's business and financial risk profile has changed since the Company's previous equity thickness proceedings (i.e., 2012).

Question:

Please provide any plans, reports, presentations, studies, or other materials created between 2012 and 2023 which address strategic business planning and/or assessments for the future of Enbridge Gas Inc.'s business (and for periods before the merger Enbridge Gas Distribution's and Union Gas' business). In this question "strategic business plans or assessments" means documents which address risks or material changes with respect to any of the following; projected and actual financial earnings and regulatory earnings (including ROR and ROE); projected and actual customer and meter counts by customer class; material operational risks or changes; material risks to attraction or retention of capital investment; marketing considerations; provincial or federal regulation; payment of dividends; any other material forward looking financial/operational risks. Please include any underlying analysis or quantification of business or financial risks identified, such as but not limited to cash flow, earnings, and historical credit spreads of EGI and US and Canadian proxies.

5.3-IGUA-30

Preamble: **Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 17 of 164**

Concentric's report states:

There are two fundamental sources of risk for any company, including regulated utilities: business risk and financial risk. Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including a fair return on, and of, its capital in a timely manner. These risks include operating risk and regulatory risk. Financial risk relates to a company's debt leverage and liquidity and is measured by its credit profile. Both business and financial risk have a direct bearing on a utility's cost of capital.

Questions:

(a) Please provide a table of EGI's (and for periods before the merger Enbridge Gas Distribution and Union Gas) allowed rate of return and return on equity and the actual rate of return and return on equity, for each year since 1990.

(b) Please provide a table, as well as the accompanying worksheets, that reports the allowed return on equity and the actual return on equity for each of the companies included in the four proxy groups, for each year since (and including) 2012.

5.3-IGUA-31

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 26 of 164

Concentric's report states:

Investor ESG concerns are already affecting capital markets, as illustrated by S&P's analysis of the financing costs of North American oil and gas companies relative to their environmental impact. Specifically, S&P grouped North American energy companies into quartiles based on the carbon intensity of their revenue as measured by the annual metric tons of carbon emissions per million dollars of annual revenue. S&P concluded that it saw "evidence that issuers with lower carbon intensity were able to issue longer-dated debt at lower financing costs than their more carbon-intense peers." Figure 6 provides the yield curves that S&P developed for new debt issuances from the companies in the highest and lowest quartiles of carbon intensity. As shown, issuers in the highest carbon intensity quartile tend to have materially more expensive debt than issuers in the lowest carbon intensity quartile. S&P estimated that differences in debt yields between the highest and lowest carbon intensity issuers exceeded 150 basis points for 10+ year issuances over the period studied. [footnote removed]

Questions:

(a) What is EGI's carbon intensity of its revenue as measured by the annual metric tons of carbon emissions per million dollars of annual revenue?

(b) Which quartile of North American energy companies based on the carbon intensity of their revenue as measured by the annual metric tons of carbon emissions per million dollars of annual revenue would EGI fall into?

5.3-IGUA-32

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 27 of 164, Figure 7

Question:

(a) Please identify which of the utilities in this figure have made emissions commitments regarding their natural gas distribution utilities.

(b) For those natural gas distribution utilities with commitments, please identify those which have made commitments regarding emissions from release of methane or other gas utility operational emissions.

(c) For those natural gas distribution utilities with commitments, please identify those which have made commitments regarding emissions from the consumption/combustion of the gas they distribute.

5.3-IGUA-33

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 33 of 164

The Concentric report states:

However, the OEB also identified three specific risks that accompany the first- generation IRP framework it approved:

• Plan Accuracy: The OEB noted that the IRP assessment process "should result in more prudent and effective integrated resource system planning," which should reduce the risk that it does not accurately identify superior alternatives to facility projects. However, the OEB also noted that it "retains the authority to deny recovery of costs if it determines that Enbridge Gas was not prudent in considering alternatives, and Enbridge Gas acknowledged this possibility."

• Success of IRP Plan Implementation: The OEB indicated that Enbridge Gas "may be at risk for recovery of some portion of IRP investments that are deemed imprudent," and that "there may be a greater degree of performance and cost risk associated with IRPAs [IRP alternatives] and IRP Plans in comparison with facility projects" because the Company has "less experience in addressing system constraints using IRPAs like geotargeted DSM or demand response, and these IRPAs depend on consumer behaviour for success."

• Stranded Assets: The OEB found that the "risk of stranded assets is a concern for both infrastructure builds and for IRPAs. The OEB has limited experience with the treatment of stranded assets. The examination of the treatment of stranding of assets in other jurisdictions and the findings of the Technical Working Group on this topic might help provide a better understanding of stranded assets and options to allocate the costs between Enbridge Gas and its customers."

Absent the Energy Transition, EGI would not be subject to these same risks, which are only partly mitigated by the OEB's approval of the Company's plans. [footnotes removed]

Questions:

(a) Regarding "Plan Accuracy": Does Concentric believe that EGI would not be subject to integrated resource planning and the obligation to prudently consider alternatives to facility projects, absent the Energy Transition? If so, why?

(b) Regarding "Success of IRP Plan Implementation": Does Concentric believe that EGI would not be at risk for recovery of some portion of its investments that are deemed imprudent, absent the Energy Transition? If so, why?

(c) Regarding "Success of IRP Plan Implementation": Does Concentric believe that IRPAs would not be considered or planned, absent the Energy Transition? If so, why?

5.3-IGUA-34

Preamble:

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 33-34 of 164

Concentric states:

Achieving net zero GHG emissions by any date is a tremendous challenge for any natural gas distribution utility, Enbridge Gas included. There are two commonly identified fuel alternatives for gas distribution utilities to comply with net zero targets: hydrogen and renewable natural gas ("RNG"). However, pursuing those pathways carries risk from an investor's perspective. This section discusses the various operational, technical, and financial concerns that investors have noted with large-scale moves towards hydrogen and RNG.

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 36 of 164

Concentric states:

Therefore, we conclude that while hydrogen may offer a potential pathway for the Company through the Energy Transition, investors perceive significant risk to that pathway because of its operational, technical, and financial challenges.

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 37 of 164

Concentric states:

These preliminary studies regarding the viability of RNG do not necessarily mean that RNG is not a viable long-term solution. However, from an investor's perspective, pursuing such an uncertain pathway intrinsically carries risk. Further, as with the hydrogen discussion above, it is a risk that was not as meaningful at the time of the Company's previous equity thickness proceedings (i.e., 2012).

Questions:

(a) Did Concentric consider energy efficiency as an alternative for EGI to comply with net zero targets?

(i) If so, please provide that analysis, including any conclusion regarding investor perception of risk. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

(ii) If not, why not?

(b) Did Concentric consider hybrid heating (that is, the use of heat pumps or other electric technologies alongside gas combustion for heating) as an alternative for EGI to comply with net zero targets?

(i) If so, please provide that analysis, including any conclusion regarding investor perception of risk. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

(ii) If not, why not?

(c) Did Concentric consider electrification as an alternative for EGI to comply with net zero targets?

(i) If so, please provide that analysis, including any conclusion regarding investor perception of risk. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

(ii) If not, why not?

5.3-IGUA-35

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 45 of 164

Concentric states:

Further, all else equal, accelerating depreciation rates will increase rate pressure for customers, rendering natural gas less competitive against alternative energy sources, mainly electricity.

Questions:

(a) Did EGI or Concentric conduct analysis to quantify the anticipated rate impact and competitive impact of accelerating depreciation rates?

(i) If so, please provide that analysis, including any spreadsheets or models used (with working formulas and links).

(ii) If no analysis was conducted, why not?

(b) Would increasing EGI's equity thickness increase rate pressure for customers, rendering natural gas less competitive against alternative energy sources?

(i) If not, why not?

(ii) Provide any analysis EGI or Concentric has conducted that considers the competitive impact of EGI's proposal to increase its equity thickness including any spreadsheets or models used (with working formulas and links).

5.3-IGUA-36

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 44-45 of 164

Concentric's report states:

Another risk of the Energy Transition is that a significant portion of the Company's gas plant investments could become stranded. Generally, the term "stranded asset" refers to an investment that becomes no longer used or useful in the provision of service to customers before the end of its depreciable life. At that point in time, the undepreciated value of the asset (i.e., its net book value) is "stranded" with costs to be borne by either investors or customers. Gas distribution utilities such as the Company generally depreciate capital invested in their systems over the expected useful life of the underlying physical property, which is often many decades. Therefore, the Energy Transition creates stranded asset risk for the Company by introducing the possibility that significant portions of the Company's property will cease being used or useful before it is fully depreciated. In fact, the OEB recently acknowledged the risk of stranded assets when evaluating the Company's IRP proposal.

...

Like Moody's, Concentric expects that the OEB will approve measures to mitigate the Company's stranded asset risk, up to and potentially including the acceleration of depreciation rates as appropriate. However, we note that this is a "downside-only" area for the Company. In other words, while regulatory changes (e.g., the acceleration of depreciation rates) may improve the Company's prospects of recovering its investment, there remains a chance that investors are not able to earn a full "return of" their invested capital.

Questions:

(a) Has Concentric or EGI (and in the case of EGI either directly, through a consultant or as part of any industry association) or any affiliate of EGI (either directly, through a consultant or as part of any industry association) conducted any financial analysis (that is, analysis of the finances of EGI as a company) for specific pathway(s) or scenarios in which the Company's investors are not able to earn a full "return of" their invested capital?

(b) If so, please identify the pathway(s) or scenarios and provide the analyses. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analyses.

(c) Has EGI identified any specific assets that are at risk of becoming stranded because of the Energy Transition or other cause?

(i) If so, please identify those assets, the conditions under which they may become stranded, and the date or timeline on which they may become stranded. Please provide copies of the spreadsheets or other models (with working formulas and links) used to conduct this analysis.

(d) Please identify all analyses conducted by EGI or otherwise in EGI's possession which analyze changes in EGI's gas system operations and maintenance costs along different potential decarbonization pathways or Energy Transition scenarios.

(i) Please provide the identified analyses. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

(e) Please identify all analyses conducted by EGI or otherwise in EGI's possession which quantify infrastructure investment on EGI's system along different potential decarbonization pathways or Energy Transition scenarios.

(i) Please provide the identified analyses. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analyses.

(f) Please identify all analyses conducted by EGI or otherwise in EGI's possession which quantify infrastructure retirements on EGI's system along different potential decarbonization pathways or Energy Transition scenarios.

(i) Please provide the identified analyses. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analyses.

5.3-IGUA-37

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 45 of 164

Concentric states:

Depending on the specific pathways ultimately taken by the Canadian federal government and the province of Ontario, the Company may no longer be able to engage in the provision of its main business enterprise: the distribution of natural gas.

Questions:

(a) Has Concentric or EGI (and in the case of EGI either directly, through a consultant or as part of any industry association) or any affiliate of EGI (either directly, through a consultant or as part of any industry association) conducted any financial analyses (that is, analysis of the finances of EGI as a company) for specific pathway(s) in which EGI is no longer able to engage in the distribution of natural gas?

(b) If so, please identify the pathway(s) and provide the analyses. Please provide copies of the spreadsheets or other models (with working formulas and links) used to conduct the analyses.

(c) In the pathway analyses conducted, were shareholders in EGI able to recover all of their invested capital? Did shareholders earn a reasonable return on that capital?

5.3-IGUA-38

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 51 of 164

Concentric's report notes:

In EB-2011-0354, the OEB found that there was "no dispute that average use has declined and continues to do so." However, the OEB determined that this development did not increase the Company's risk relative to 2007 (i.e., the period in which the OEB had previously examined the Company's equity thickness) for several reasons, including:

- *Declines in use per customer are mitigated by customer additions.*
- *Shale gas strengthens the competitive position of natural gas relative to alternative fuel sources such as oil and electricity.*
- *Regulatory mechanisms such as rate design and deferral and variance accounts protect the Company's revenues from declines in its sales volumes.*
- *A "death spiral" is unlikely from declines in average use per customer because declining usage also decreases commodity costs. [footnotes removed]*

Questions:

(a) Please provide an analysis of the relative cost of natural gas versus electricity and fuel oil or other energy sources for a typical customer in the following categories for each year since 2000. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis:

(i) Residential using natural gas for heating and cooking

(ii) Commercial using natural gas for heating

(iii) Large volume industrial users

(iv) Small volume industrial users

(b) Please provide an analysis of the competitiveness of natural gas for new residential customers in new developments relative to electricity. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis

(c) Please indicate the number of units and percentage of new residential housing that choose natural gas, electricity and other fuels for each year since 2000 in EGI's franchise area.

(d) Please indicate the typical cost of converting a current residential natural gas user to electricity (heat pump or resistance heating).

5.3-IGUA-39

Preamble: EB-2011-0354, Decision on Equity Ratio and Order, February 7, 2013, at 11

The referenced OEB decision includes the following passage:

Mr. Coyne expressed the view, however, that increasing the proportion of fixed costs "sets the stage for the so-called, quote-unquote death spiral" by decreasing customers' opportunity to economize by decreasing consumption. In his view, this could cause significant fuel-switching. The Board considers that this does not take account of the fact that if average use declines, the customer's commodity costs will decline. Given that 49% of distribution revenues are still collected through variable charges, this means that the customer's overall bill will also decline. The evidence does not indicate that a "death spiral" situation will likely arise in the near term. [footnote removed]

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 57 of 164

Concentric's report states:

We note that the Company is proposing a SFV rate design in this case. If approved, this proposal would further decrease the Company's exposure to volumetric risk. We note that the Company continues to benefit from regulatory mechanisms such as deferral and variance accounts that mitigate the potential financial impact of declining sales volumes (although these accounts may be discontinued if the Company's SFV proposal is approved). For these reasons, we conclude that the Company has regulatory mechanisms that mitigate the Company's volumetric risk in the near-term. However, as discussed in more detail in the following section, we conclude that the Company's long- term volumetric risk has increased.

Questions:

(a) Does Mr. Coyne/Concentric believe that the SFV rate design proposed in this case increases the risk of a "death spiral" or otherwise increases long-term volumetric risk by decreasing customers' opportunity to economize by decreasing consumption, which could cause significant fuel-switching?

(b) Does Mr. Coyne/Concentric believe that a "death spiral" situation for EGI will likely arise in the near term?

(i) If so, under what conditions would a "death spiral" situation arise in the near term?

(ii) Please provide any analysis used to support this conclusion. Please provide copies of the spreadsheets or models (with working formulas and links) used to conduct the analysis.

(c) What definition does Mr. Coyne/Concentric use for "near term" in this context?

5.3-IGUA-40

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 58 of 164

Concentric states:

A future "death spiral" is far from certain, and we anticipate that the Company will work proactively to avoid such an outcome.

Questions:

(a) Please identify all actions that Concentric or EGI have evaluated or analyzed that the Company could use to "work proactively to avoid such an outcome."

(b) Please provide the evaluations or analyses conducted. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analyses or evaluations.

5.3-IGUA-41

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 58 of 164

Concentric's report states:

In 2020, residential customers accounted for approximately 57% of the Company's revenues but just 32% of its sales volumes. If a meaningful portion of these customers switch to non-gas heating sources, whether due to technological advancements, environmental concerns, or policy mandates, costs will increase for the Company's remaining customers. Such a scenario could potentially spark a so-called "death spiral."

Questions:

(a) Please define "meaningful" as used in this sentence.

(b) Please define "spark" as used in this sentence.

(c) Have Concentric or EGI quantified the number of customers switching to non-gas heating sources that would be required to "spark a so-called 'death spiral'" as referenced in this sentence? If so, how many customers? Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

5.3-IGUA-42

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 58 of 164

Concentric states:

Due to the acceleration of declines in average use per residential customer, declines in the rate of customer additions, a relatively weaker economic growth outlook, the OEB's encouragement of competition, and the Energy Transition pressures, we conclude that the risk of a "death spiral" is higher today than it was in 2012.

Questions:

(a) Please describe in detail how "acceleration of declines in average use per residential customer" is causally related to the risk of a "death spiral."

(b) Have Concentric or EGI quantified the impact of "acceleration of declines in average use per residential customer" on the likelihood of a "death spiral" or the conditions or timeframe under which a "death spiral" occurs? If so, please provide the analysis conducted. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

(c) Please describe in detail how "declines in the rate of customer additions" is causally related to the risk of a "death spiral."

(d) Have Concentric or EGI quantified the impact of "declines in the rate of customer additions" on the likelihood of a "death spiral" or the conditions or timeframe under which a "death spiral" occurs? If so, please provide the analysis conducted. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

(e) Please describe in detail how "a relatively weaker economic growth outlook" is causally related to the risk of a "death spiral."

(f) Have Concentric or EGI quantified the impact of "a relatively weaker economic growth outlook" on the likelihood of a "death spiral" or the conditions or timeframe under which a "death spiral" occurs? If so, please provide the analysis conducted. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

(g) Please describe in detail how "the OEB's encouragement of competition" is causally related to the risk of a "death spiral."

(h) Have Concentric or EGI quantified the impact of "the OEB's encouragement of competition" on the likelihood of a "death spiral" or the conditions or timeframe under which a "death spiral" occurs? If so, please provide the analysis conducted. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

(i) Please describe in detail how "Energy Transition pressures" is causally related to the risk of a "death spiral."

(j) Have Concentric or EGI quantified the impact of "Energy Transition pressures" on the likelihood of a "death spiral" or the conditions or timeframe under which a "death spiral"

occurs? If so, please provide the analysis conducted. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

5.3-IGUA-43

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 58 of 164

Concentric states:

Further, while the Company benefits from a variety of ratemaking mechanisms that provide risk insulation in the short-term, regulation can do little to mitigate these longer-term pressures because this scenario is driven by economics, not regulatory pressures.

Questions:

(a) Please identify all regulatory mitigation methods that Concentric or EGI have analyzed in order to conclude that "regulation can do little to mitigate these longer-term pressures."

(i) Please provide the analysis conducted. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

(b) Please identify all economic analysis of EGI conducted by Concentric or EGI, or that are otherwise in EGI's possession or accessible by EGI, of the "scenario…driven by economics" referred to in this sentence.

(i) Please provide the identified analysis. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

5.3-IGUA-44

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 66-67 of 164, Figure 20

Questions:

(a) Please provide the workpapers (with working formulas and links) used to calculate the values in Figure 20.

(b) Has EGI or anyone on its behalf conducted, or does EGI have access to, an analysis quantifying the impacts on EGI's Debt/EBITDA, FFO/Debt, FFO/Interest Coverage, EBIT/Interest Coverage, or Debt/Capitalization of any of the following;

(i) Changes in depreciation rates

(ii) Infrastructure investment

(iii) Infrastructure retirement

(iv) Any decarbonization pathway

(c) Please provide each analysis identified in part (a) of this question. Please provide copies of the spreadsheets or models (with working formulas and links) used to conduct the analysis.

5.3-IGUA-45

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 70 of 164

Concentric states:

Risks influenced by climate change, such as severe weather events, or resulting directly from climate change, such as those due to higher temperatures and changing precipitation patterns are, therefore, increasing for EGI.

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 71-72 of 164

Concentric states:

McKinsey and Company published a report in April 2019 in which the consulting firm made specific recommendations to the utility industry with regard to managing climate change risk. While noting that severe weather events such as hurricanes and wildfires are getting worse, McKinsey wrote: "In other ways, too, utilities are more vulnerable to extreme weather events than in the past." The report went on to observe: "Unless utilities become more resilient to extreme weather events, they put themselves at unnecessary risk, in both physical and financial terms. Repairing storm damage and upgrading infrastructure after the fact is expensive and traumatic." McKinsey also quoted from a 2018 report by the National Climate Assessment that stated "utilities could see negative impacts from increased temperatures and heat waves, as well as sea level rises even in the absence of storms. This will increase the financial cost to utilities of climate change and increase the benefits of being prepared." [footnotes removed]

Questions:

(a) Please provide EGI's best estimate of its (or its predecessor companies') annual cost for "Repairing storm damage and upgrading infrastructure after the fact" for each year from 2012 to the present, as well as EGI's best estimate of that annual cost for any future year for which such an estimate has been prepared.

(b) Please provide EGI's best estimate of its annual cost of "negative impacts from increased temperatures and heat waves, as well as sea level rises even in the absence of storms" and "changing precipitation patterns" for each year from 2012 to the present, as well as EGI's best estimate of that annual cost for any future year for which such an estimate has been prepared.

5.3-IGUA-46

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 79 of 164

Concentric states:

As discussed previously, starting around 2016, the OEB has encouraged competition in EGI's service territory. Specifically, in certain cases in which EGI or its predecessors informed the OEB of its intent to serve an expanded area, the OEB issued a letter inviting other parties to compete for that service. The affirmation of competition has also been evidenced by EPCOR's successful entrance in the Bruce community. This allowance for competition in community expansions increases risk for EGI. [footnote removed]

Questions:

Regarding the mechanism by which EGI's risk is increased by competition to serve expanded areas:

(a) Does such competition increase variability and uncertainty in short-term annual return on equity? If so, how?

(i) Please identify any modeling or quantitative analysis in Concentric's or EGI's possession regarding the extent of such competition's impact on this risk.

(ii) Please provide that analysis. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

(b) Does such competition increase risk of stranded assets or other risks related to the return of invested capital? If so, how?

(i) Please identify any modeling or quantitative analysis in Concentric's or EGI's possession regarding the extent of such competition's impact on this risk.

(ii) Please provide that analysis. Please provide copies of the spreadsheets (with working formulas and links) used to conduct the analysis.

5.3-IGUA-47

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 81 of 164, Figure 22

Questions:

(a) Please provide an update to the column labeled "2022 YTD" to reflect the entirety of calendar year 2022.

(b) Please provide all workpapers and input data used to produce this figure, as well as the update for the full year 2022. Please include all data regarding "US Gas Utilities" and "Canadian Utilities" as defined in this figure.

5.3-IGUA-48

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 92 of 164, Figure 29

Questions:

(a) Did Concentric consider the analysis conducted for, and results of, the depreciation study presented as Exhibit 4, Tab 5, Schedule 1, Attachment 1, when considering the comparison between EGI and proxy groups?

(b) Did Concentric consider the results of that depreciation study regarding the difference between "calculated accumulated depreciation" and "allocated actual booked amount"?

(c) If the answers to parts (a) or (b) of this question are in the affirmative, in what way did Concentric's consideration of the depreciation study inform its conclusions regarding the suitability of comparing EGI's remaining life and % depreciated to the proxy groups?

(d) If the answers to parts (a) and (b) of this question are in the negative, why did Concentric not consider the depreciation study's results?

5.3-IGUA-49

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 92 of 164

Concentric states:

Further, as shown in Figure 30, approximately two thirds of Ontario's residents use natural gas for space heating, which ranks third among all Canadian provinces. This means that the Company faces relatively higher risk than other Canadian gas utilities due to its exposure to customers that could leave its system via conversions to alternative fuels, including electrification.

Questions:

(a) Has EGI or any of its consultants or affiliates or their consultants conducted analysis to quantify the "relatively higher risk" compared to other Canadian gas utilities referred to in this statement? If so, please provide the analysis with all supporting workpapers in electronic form (with working formulas and links). If not, why not?

(b) Please describe in detail the causal relationship between (1) the proportion of households in a province that use natural gas for space heating and (2) relative risk due to exposure to customers that could leave a gas utility via conversions to alternative fuels.

5.3-IGUA-50

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 109 of 164

Concentric states:

These analyses demonstrate that gas distribution utilities are, on average, trading at a discount to their electric utility peers. This shift occurred in the second half of 2018, which is consistent with the timing of credit rating agencies implementing ESG criteria and with certain institutional investors and pension funds adopting more stringent limits or restrictions on their ability to own shares in fossil-fuel companies that contribute significantly to higher carbon and greenhouse gas emissions.

Questions:

(a) Please provide the workpapers and complete analyses that "demonstrate that gas distribution utilities are, on average, trading at a discount to their electric utility peers."

(i) Please include annual or sub-annual data necessary to evaluate the claim that "This shift occurred in the second half of 2018"

(b) Please identify the specific events or statements that Concentric is referring to when it refers to "the timing of credit rating agencies implementing ESG criteria and with certain institutional investors and pension funds adopting more stringent limits or restrictions on their ability to own shares in fossil-fuel companies that contribute significantly to higher carbon and greenhouse gas emissions." Please provide the date and particulars of each such event or statement.

5.3 -IGUA-51

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 83 of 164

Concentric states (emphasis added):

Those measures provide relevant data from which to determine where, within a reasonable range, Enbridge Gas' deemed equity ratio should be set by the OEB, with the regulated operating company equity ratios being ***most applicable*** *for purposes of assessing Enbridge Gas' regulated equity thickness.*

Question:

Please explain precisely how Concentric accounted for the fact noted above that regulated operating company equity ratios are the "most applicable" for Assessing Enbridge Gas' (EG) equity thickness. For example, were the results from these two samples weighted heavier? If so, please state the weightings used for analysis purposes, and the justification for these weights? If they were not weighted heavier, please explain why not (given the statement above)?

5.3 -IGUA-52

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 83 of 164

Concentric constructed the US operating company sample by selecting the *"ten largest US natural gas distribution utilities, as measured by net utility plant, gas customers, and sales volumes."*

Questions:

(a) How many companies were evaluated before narrowing it down to just ten?

(b) Please explain why Concentric decided to limit this sample to the "ten largest."

5.3-IGUA-53

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 84 of 164

Figures 23 and 24 provide equity ratio summary statistics for the various proxy groups.

Questions:

(a) Please confirm that the mean and median figures for "2-Year Avg. Book Equity Ratio" that are presented in Figure 23 and Figure 24 respectively, are determined using observations for only four of the 10 Canadian operating companies in this proxy group.

(b) Please confirm that one of the four observations used to determine the mean and median figures for "2-Year Avg. Book Equity Ratio" for the Canadian operating company proxy group, which are presented in Figure 23 and Figure 24, was an outlier of 49.92% for FortisBC Energy, which also greatly exceeded its' authorized equity ratio of 38.5%.

(c) Please confirm that if the equity ratio of 49.92% for FortisBC Energy was excluded, the average for "2-Year Avg. Book Equity Ratio" for this proxy group would be 40.42%, and the median would be 38.8%.

5.3-IGUA-54

Preamble:

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 85 of 164

Concentric notes that when constructing proxy groups that the NERC recommends "*the inclusion of companies with credit ratings no more than one notch above or below the utility or utilities whose rate is at issue.*"

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 89 of 164

Concentric notes that "Enbridge Gas has an "A" issuer and unsecured debt rating from DBRS, and an "A-" corporate and unsecured debt credit rating from S&P."

Questions:

(a) Please provide all available debt rating reports (i.e., DBRS, Moody's, Fitch and DBRS) for Enbridge Gas for the last two years.

(b) For comparison purposes to Enbridge Gas, please provide all current available debt ratings (i.e., DBRS, Moody's, Fitch and DBRS), as well as the supporting most recent debt rating reports for all 34 companies used in the four proxy groups.

(c) Given the NERC criterion pointed out by Concentric on page 85 noted above, please explain why Concentric (page 89) decided to implement the following screening criteria for companies to be included in the US holding company proxy group – "Have an investment grade credit rating." I.e., since companies with a BBB- rating for example, would lie 3 to 4 notches below the credit rating for Enbridge Gas. Why not increase the stringency of this screen to BBB+ or above?

(d) Please confirm that during the current General Cost of Capital (GCOC) Proceedings taking place in Alberta, in the fall of 2022 Concentric recommended including US companies in their "North American" sample if they had "credit ratings of at least BBB+ from S&P or Baa1 from Moody's." If not confirmed, please clarify.

(e) Please explain why Concentric has decided to "relax" this screening criterion during these proceedings.

(f) Please confirm that during the current Alberta GCOC Proceedings mentioned in part (d), the Alberta Utilities Commission (AUC) recommended that US companies be included in proxy groups only if they had credit ratings of at least BBB+ or Baa1. If not confirmed, please clarify.

5.3-IGUA-55

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 89 of 164

Concentric states:

The last proxy group (i.e., the US HoldCo Proxy Group) is comprised of publicly-traded US natural gas distribution companies that would be considered by investors as generally comparable in risk to Enbridge Gas.

In order to construct its proxy group of US Holding Companies, Concentric notes:

To obtain companies of like risk, we performed a number of screens to develop a group of companies that are primarily engaged in the provision of regulated natural gas distribution utility service.

Concentric then starts with "the ten domestic companies that Value Line classifies as natural gas utilities," before applying three additional screens, including;

(i) an "investment grade credit rating" criterion;

(ii) having regulated net income that makes up greater than 60% of total income for the consolidated company; and

(iii) having regulated gas net income that makes up greater than 60% of net income for the consolidated company's regulated operations.

Questions:

(a) For each of the Holding Companies included in **both** the Canadian and US Holding company proxy groups, please provide the following information:

(i) The size of the company in terms of revenue and total assets.

(ii) A list of all operating companies that are subsidiaries of each utility, as well as the jurisdiction(s) in which each of these companies and their subsidiaries operate.

(iii) The percentage breakdown of revenue, operating earnings and net income from each of the operating companies identified in part (ii).

(iv) The percentage breakdown of regulated versus unregulated revenue, operating earnings and net income for the utilities.

(v) The percentage breakdown of regulated versus unregulated revenue, operating earnings and net income for each utility broken out between operations that are based in Canada, versus operations that are based in other countries.

(vi) A similar percentage breakdown to that requested in part (iv) as between operations related to transmission, distribution, generation, and other activities.

(b) Please confirm that during the current GCOC Proceedings taking place in Alberta and in the fall of 2022 Concentric recommended including US companies in their "North American" sample if they satisfied the two following criteria:

(i) derived at least 90 percent of operating income from regulated operations in the most recent three year period (in this case, 2019-2021); and

(ii) derived at least 70 percent of regulated operating income from electric utility service in the most recent three-year period (for electric utilities), or at least 65 of regulated operating income from gas distribution service in the same period (for gas utilities).

If not confirmed, please clarify.

(c) Please explain why Concentric has decided to change (and "relax") these screening criteria during these proceedings.

(d) Please confirm that during the current Alberta GCOC Proceedings mentioned in part (b), the AUC determined that US utilities would be excluded from proxy groups if:

(i) less than 80 per cent of their assets are associated with rate regulated activities regardless of whether those assets consist solely of electric utility operations, natural gas utility operations or a combination of both; or

(ii) less than 75 per cent of their operating income is from rate regulated utility operations.

5.3 -IGUA-56

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Pages 91-92 of 164

Concentric states:

All else equal, relatively higher remaining book lives and/or relatively lower depreciation rates indicate that it will take longer for an investor to recover the return of invested capital, therefore increasing exposure to Energy Transition risks such as stranded asset risk and volumetric risk.

Figure 29 provides summary statistics regarding "Remaining Life," etc. for Enbridge Gas and the various proxy groups.

Questions:

(a) Can Concentric provide empirical support for the cited statement? For example, is there empirical evidence showing that the required rate of return on equity for companies with longer-lived assets is higher than for those with shorter-lived assets?

(b) Is Concentric suggesting that investors would prefer to invest in companies whose assets are older and nearer the end of their useful lives? If so, please explain the logic behind this assertion. If not, please explain why this is not a corollary of the suggestion that investing in companies with newer and less depreciated assets is riskier than investing in companies with older and more depreciated assets.

(c) Would having assets that are newer actually **reduce risk** for companies? For example, wouldn't this imply the company would have to allocate relatively less to future capital expenditures to upgrade assets than would comparable companies with older assets?

5.3-IGUA-57

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Pages 94-96 of 164

Concentric discusses regulatory rankings of Ontario and other jurisdictions and provides a summary of these rankings in the form of averages in Figure 31. We are interested in seeing greater detail regarding how these averages were determined, as well as the rankings for the individual companies included in the various proxy groups, and how they were weighted.

Questions:

(a) Please provide a figure identical to Figure 31 that provides the **median** rankings for the various proxy groups.

(b) Please provide the rankings for **all companies** included in the proxy groups, including a description of how these company rankings were determined, given that many of the companies own and operate utilities in numerous jurisdictions. For example, were the company rankings determined by using "simple" averages of all the operating companies under ownership, or were they weighted by revenue, income, etc. related to the various operating companies that are owned by holding companies?

5.3 -IGUA-58

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Pages 96-98 of 164

On pages 96-98, Concentric discusses five regulatory mechanisms available to Enbridge Gas and estimates the percentages of the companies in the proxy groups operating in other jurisdictions that also have similar mechanisms available to them. Concentric provides a summary of this analysis in Figure 32. We are interested in seeing greater detail regarding how these averages were determined, as well as the ratings for the individual companies included in the various proxy groups, and how they were weighted.

Questions:

(a) Footnote 214 notes that "Information is not readily available for several of the companies in the Canadian OpCo proxy group." Please state how many of the 10 companies included in this sample were actually used to determine the percentages reported in Figure 32 for this proxy group.

(b) Please state how many of the companies included in the other three proxy groups were actually used to determine the percentages reported in Figures 32 for the respective proxy group.

(c) Please explain clearly how these percentages for the various companies included in the proxy groups (provided in Schedule 3), were determined, given that many of the companies own and operate utilities in numerous jurisdictions. For example, were the company rankings determined by using "simple" averages of all the operating companies

under ownership, or were they weighted by revenue, income, etc. related to the various operating companies that are owned by holding companies?

(d) Please confirm that the average percentages across all four proxy groups for the five regulatory mechanisms available to the companies in the proxy groups are all well below 100%, with average (and range) percentages respectively of: 45.5 (40-56); 65.3 (42-80); 79.0 (61-100); 75.8 (67-83); and, 54.8 (39-80). If not confirmed, please provide the calculated averages and ranges for the five regulatory mechanisms.

(e) On page 98 Concentric states (bold added for emphasis) that "On the basis of the above, Concentric concludes that Enbridge Gas is **comparable** to the proxy companies…" In fact, since Enbridge Gas answers yes (i.e., 100%) with respect to the existence of all five regulatory mechanisms examined, versus proxy group percentages that are much lower, doesn't Concentric's analysis as provided in Figure 32 actually demonstrate that Enbridge Gas has **lower regulatory risk** relative to all four proxy groups based on its' access to these five regulatory mechanisms? Please explain your answer.

5.3 -IGUA-59

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 99 of 164

Concentric states (emphasis added):

While the Company is quite large as measured by customers, sales, assets, etc., its operations are limited to natural gas distribution in Ontario, Canada. This ***lack of regulatory and geographic diversity partially mitigates the risk reductions*** *created by the Company's large size.*

Questions:

(a) Concentric has stated previously that the operating company proxy groups are the "most applicable" to Enbridge Gas. Therefore, if we first look at these two most applicable proxy groups, please confirm that this statement would also apply to the 10 operating companies included in the Canadian Operating Company Proxy Group, as well as to the 10 companies included in the US Operating Company Proxy Group. I.e., they also operate in one jurisdiction and geographic region as well. If not please explain.

(b) Turning attention to the two (less applicable) holding company proxy groups, please confirm that jurisdiction exposure for the two holding company proxy groups range from (average): one jurisdiction (for two companies) to five, with an average of 3.2 for the six Canadian holding companies; and, one jurisdiction to eight, with an average of 3.4 for the eight US holding companies. If not confirmed please provide the range and average for these two proxy groups.

(c) Given that the 20 companies included in the two most applicable groups (i.e., operating companies) have no additional regulatory or regional diversity; and (b) there is very little additional diversity, please justify the statement: "This lack of regulatory and geographic diversity partially mitigates the risk reductions created by the Company's large size."

(d) The S&P rankings provided in Figure 31 show that Ontario is a more highly rated regulatory jurisdiction than those for the average company in the proxy groups, and the evidence provided in Figure 32 shows that Enbridge Gas has superior regulatory support mechanisms than all of the proxy groups that operate in various other jurisdictions. Given this evidence provided by Concentric, please explain why being located in one "above average" supportive regulatory environment would actually increase risk for Enbridge Gas, as opposed to proxy group companies operating across several less supportive regulatory environments, where the average level of supportiveness is lower.

5.3-IGUA-60

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Pages 101-103 of 164

On pages 101-103, Concentric provides an equity ratio comparison of Enbridge Gas to the four proxy groups. Concentric provides a summary of this analysis in Figure 34 (averages) and Figure 35 (medians), which replicate the previous Figures 23 and 24 provided on page 84.

Questions:

With respect to the six companies included in the second proxy group in these tables (i.e., the Canadian Holding Companies group), please confirm the following:

(i) Four of the five operating companies referenced for Algonquin are US-based, with only one Canadian company.

(ii) All five of the AltaGas Inc. operating companies referenced are US-based.

(iii) The only company referenced for CU Ltd. is ATCO Gas, which is Canadian-based (Alberta).

(iv) Both of the two operating companies referenced for Emera are US-based.

(v) Two of the three operating companies referenced for Fortis are US-based, with FortisBC Energy being the lone Canadian company referenced.

(vi) The only operating company referenced for Hydro One is Canadian-based; however, no data is provided.

5.3-IGUA-61

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Pages 103-104 of 164

Concentric discusses credit metrics for Enbridge Gas and the four proxy groups, and reports these metrics in Figure 37 on page 104.

Questions:

(a) Please provide the detailed formulas used to calculate all five ratios reported in Figure 37.

(b) Please provide a table that provides S&P guidance regarding each of these credit metrics with respect to debt rating categories for utilities. For example, would an "EBITDA Interest Coverage" ratio ≥ 2.0 correspond to an A or A- rating for a low business risk utility, for example?

(c) Please provide all data and workpapers used to calculate the credit metrics for "Enbridge Gas Inc. (Reg-only)".

(d) Please provide all data and workpapers used to calculate all of the reported credit metrics for each company included in each proxy group. Provide all sources for these metrics (i.e., S&P debt rating reports, etc.).

(e) For comparison purposes with the reported proxy group metrics, please report the credit metrics for all companies included in the proxy groups using only regulated operations, similar to the credit metrics for reported for "Enbridge Gas Inc. (Reg-only)". This is required to assess the informativeness of the "Enbridge Gas Inc. (Reg-only)" reported metrics.

(f) Please provide all data and workpapers used to calculate the "regulated operations only" credit metrics calculated for all proxy group companies as requested in part (e).

(g) Please confirm that Concentric's credit metric analysis is based on the metrics of 13 of the 14 companies included in the two Holding Company samples, does not report or rely on metrics for the 10 companies included in the CanadianOpCo group, and uses only 7 of the 10 companies included in the USOpCo group. Please explain how such an approach, which heavily weights (i.e., uses 13 of 14) holding companies, and provides a much lower weighting to operating utilities (i.e., uses only 7 of 20), is consistent with Concentric's statement (on page 83) that the regulated operating company samples were the "most applicable for purposes of assessing Enbridge Gas' regulated equity thickness."

(h) Please provide a table similar to Figure 37, with historic data and all supporting data and working papers used to calculate the credit metrics 2011-2020 for each of:

(i) Enbridge Gas Inc. (S&P)

(ii) Enbridge Gas Inc. (Reg-only)

5.3 -IGUA-62

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Pages 104-105 of 164

Concentric provides a comparison of Enbridge Gas' weighted returns on equity to those for the four proxy groups. Concentric provides a graphic summary of this analysis in Figure 38.

Concentric states:

As a result, the Company's weighted authorized return on equity (3.12%) is substantially below that of other Canadian operating gas utilities (3.94% on average) and recent U.S. gas decisions (4.83% on average).

Questions:

(a) Please confirm the US data depicted in Figure 38 references the data for 55 US operating companies, and includes data for only three of the 10 US operating companies included in the US Operating Companies Proxy Group. If not confirmed please explain.

(b) Please confirm that using the data for only the three companies included in the US Operating Companies Proxy Group the average ROE would be 9.48%, the average equity ratio would be 47.2%, and the average weighted authorized return on equity would be 4.47%. If not confirmed please explain.

(c) Please explain why Concentric chose to use 55 utilities for this analysis, including 52 that were not included in the US Operating Companies proxy group, a group that Concentric constructed with the intention of being most comparable to Enbridge Gas.

(d) Please reconstruct Figure 38, and provide all supporting data and worksheets, using only data for the 10 companies included in the US Operating Companies proxy group.

5.3-IGUA-63

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Pages 108-109 of 164

Concentric discusses Gas utilities trading at a discount to electric utilities, and states:

Concentric examined financial and valuation measures to evaluate the relative risk of the natural gas distribution and electric utility sectors, including: 1) forward P/E ratios, and 2) Beta coefficients. We compared these measures for the natural gas LDC proxy group companies and the Value Line Electric Utility universe in 2021 versus the same measure in 2012. As discussed in this section of the report, Concentric's analysis demonstrates that investment risk (which includes both business risk and financial risk) for natural gas distribution companies has increased relative to electric utilities. Whereas gas distributors were traditionally viewed as having somewhat lower risk profiles than electric utilities, now the opposite is true, with investors perceiving higher risk for gas distributors as compared to electric utilities. This supports our recommendation that the deemed equity ratio for EGI should increase, particularly when considered in the context of the OEB's deemed equity ratio for electric distributors at 40%.

Concentric further states that:

These analyses demonstrate that gas distribution utilities are, on average, trading at a discount to their electric utility peers.

Questions:

(a) Please provide all data, worksheets, and a summary table providing the results of Concentric's analysis of forward P/E ratios and betas. In particular, please provide:

(i) The data, worksheets and summary stats for the LDC Proxy group (and for each company included in this proxy group), and for the Value Line Electric Utility universe for forward P/E ratios and betas for the years from 2012-2022 inclusive.

(ii) The calculations and figures (i.e., averages, medians, etc.) for forward P/E ratios and betas (including the sources for such information) used to arrive at Concentric's conclusions.

(b) The price-to-book (P/B) ratio is a more commonly used measure (than P/E ratios) for assessing whether or not companies are trading at a premium or discount in financial practice, since it provides information regarding whether or not a company trades above or below the book values of their assets. Please provide the P/B ratios for the LDC Proxy group (and for each company included in this proxy group), and for the Value Line Electric Utility universe for the years from 2012-2022 inclusive. Please provide all data, worksheets, and a summary table providing the results of this analysis.

(c) Please explain why Concentric asserts that higher betas would indicate "a discount to their electric utility peers."

(i) Please provide any academic or empirical support for this statement.

(ii) Would Concentric agree that financial theory would suggest that the prices of companies with higher betas would reflect these higher betas. If Concentric disagrees, please explain.

(iii) Over the period referenced by Concentric (i.e., 2012-2021), the data provided by Concentric in Exhibit 5 shows that stock returns on the TSX Index averaged 6.03%, and the S&P500 Index averaged 14.07%. Would Concentric agree that stocks with higher betas are more likely to display greater price increases than stocks with lower betas during such periods of positive market returns (i.e., since by the definition of beta their prices would be more likely to increase even more than the average market increase during upswings)? For example, stocks with high betas can frequently trade at huge (and sometimes unjustifiable) premiums relative to other stocks with lower betas, such as high-tech stocks did during the 1998-2001 period. If Concentric disagrees with this observation, please explain why.

(iv) Given that stocks with higher betas will, by definition, increase more than stocks with lower betas, please explain why Concentric argues that higher betas (if they exist) are indicative of stocks trading at a discount.

5.3-IGUA-64

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 109 of 164

Concentric discusses betas with respect to Gas utilities trading at a discount to electric utilities. Concentric includes Figure 40, which includes Bloomberg beta coefficients. Concentric states that:

Figure 40 below demonstrates that five-year weekly Beta coefficients from Bloomberg for gas distributors are currently somewhat lower than for electric utilities but have increased to a greater degree since 2012.

Questions:

(a) Please confirm that it is common practice to determine betas using weekly data using the previous two years of weekly data, and not the previous five years of data. Please also confirm that using two years of weekly data is the Bloomberg "default", as well as for the majority of finance professionals that do such calculations on their own. If not confirmed, please explain and provide supporting data/references.

(b) Please confirm the betas presented in Figure 40 for the Canadian Proxy Group are determined using the betas for the companies included in the Canadian Holding Company proxy group. If not confirmed, please explain how these betas were determined.

(c) Please provide both the adjusted betas and the raw betas for all companies used in determining the Canadian Proxy Group betas provided in Figure 40, and denote which ones (i.e., adjusted or raw betas) were used in calculating the reported beta.

(d) Please confirm the betas presented in Figure 40 for the US Gas Proxy Group are determined using the averages for the companies included in the US Holding Company proxy group. If not confirmed, please explain how the reported betas are determined.

(e) Please provide both the adjusted betas and the raw betas for all companies used in determining the US Gas Proxy Group betas provided in Figure 40, and denote which ones (i.e., adjusted or raw betas) were used in calculating the reported beta.

(f) Please explain how the betas presented in Figure 40 for the "U.S. Electric Utility Group ex-PG&E" group are determined using the betas for the companies included in this group.

(g) Please provide both the adjusted betas and the raw betas for all companies used in determining the "U.S. Electric Utility Group ex-PG&E" provided in Figure 40, and denote which ones (i.e., adjusted or raw betas) were used in calculating the reported beta.

(h) Please confirm "adjusted betas" are determined using the following equation, which adjusts a raw (unadjusted) beta towards "1": Beta(adjusted) = (2/3)(Raw Beta) + (1/3)(1). If not confirmed, please explain.

(i) Please provide both the adjusted betas and the raw betas for the summary measures provided for the three proxy groups presented, as well as for all companies used in determining the three proxy sample betas provided in Figure 40 from 2012-2021 as

estimated using: (i) five years of weekly data; (ii) two years of weekly data; and, (iii) five years of monthly data.

(j) Please reproduce Figure 40 using raw betas for all years from 2012 to 2021 inclusive, based on: (i) five years of weekly data; (ii) two years of weekly data; and, (iii) five years of monthly data.

5.3-IGUA-65

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Pages 112-114 of 164

Concentric discusses equity reports and P/E ratios for Canadian and US utilities. Based on an examination of Figure 41, Concentric concludes that:

The valuation of Canadian utilities declined substantially relative to U.S. utilities over the 2010-2022 timeframe. Specifically, Canadian utilities traded at an approximately 56 percent premium to U.S. utilities in 2012, an approximately 21 percent discount to U.S. utilities in 2019, and are trading at a slight discount (i.e., approximately 4 percent) to U.S. utilities so far in 2022.

Questions:

(a) Please confirm that over the period referenced by Concentric (i.e., 2012-2021), the data provided by Concentric in Exhibit 5 shows that stock returns on the TSX Index averaged 6.03% versus 14.07% (i.e., Canadian returns were 57.1% lower), while Canadian utilities returned an average of 9.03% versus 11.46% returned by US utilities (i.e., Canadian utility returns were only 20.3% lower). If not confirmed then please provide the actual numbers and percentages of difference.

(b) Please confirm the P/E ratio for the TSX Index was 12.8 at the end of 2022, while the P/E ratio for the S&P500 Index was 18.6 (i.e., the TSX Index P/E was 31.1% *lower*); while at the end of 2012 the P/E ratio for the TSX Index was 15.8 and the P/E ratio for the S&P500 Index was 14.4 (i.e., the TSX Index P/E was 9.8% *higher*). If not confirmed then please provide the actual numbers and the percentage differences.

(c) Given the fact that Canadian market returns were 57% lower than US market returns over this period, as reflected in the fact that the TSX Index P/E ratio was 31% lower than that for the S&P 500 at the end of 2022, versus having a 9.8% higher P/E ratio at the end of 2012, isn't it more reasonable to assume the small "discount" to Canadian utility P/Es in 2022 is mostly attributable to the weaker performance of the broader Canadian stock market relative to the US market, than to investors' assessments of the relative risk of Canadian versus US utilities? If not, please explain why not.

5.3-IGUA-66

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Pages 115-117 of 164

Concentric discusses credit agency perspectives regarding the relative risks of Canadian versus US utilities.

Questions:

(a) Please confirm that the entire discussion in this section is based on a 2013 Moody's article. If not confirmed, please provide all additional material that Concentric relied on at the time that its evidence was written.

(b) On page 116, Concentric provides a quote from the 2013 Moody's report that states "US regulated utilities in recent years have exhibited stronger financial ratios relative to similarly rated regulated international utility peers." Please confirm that this observation is simply a by-product of the higher allowed ROEs and equity ratios in the US that existed at the time, and still do. If not confirmed, please explain.

5.3-IGUA-67

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Pages 117-120 of 164

Concentric discusses North American utility merger activity and notes:

Since 2000, we identified 22 transactions where a Canadian utility acquired a U.S. utility and three where a U.S. utility acquired a Canadian utility.

On page 120, Concentric concludes:

In other words, our analysis shows that Canadian utilities are choosing to invest in U.S. where higher returns are available than in Canada. This is direct market evidence of better potential reward for taking on a similar level of risk.

Questions:

(a) Please explain why Concentric suggests such evidence implies a "similar level of risk" for Canadian and US utilities. Specifically, please explain why this isn't actually a "return" (or excess return) story, since US utilities in general receive higher allowed ROEs and higher equity ratios than Canadian utilities – which is consistent with US utilities displaying higher risk.

(b) A bottom line measure of risk is the ability of utilities to earn their allowed ROE. Please reconcile Concentric's assertion that US utilities possess similar risk to Canadian utilities with the observation that most Canadian operating utilities earn *above* their allowed ROE, whereas the average US utility earns *below* their allowed ROE.

5.3-IGUA-68

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 81 of 164

Concentric provides average P/E ratios, P/B ratios, betas and debt ratings for Canadian and US gas utilities in Figure 22.

Questions:

(a) Please explain why, in determining the averages for these variables, Concentric included the six utilities included in the Canadian Holding Company sample, but also included Enbridge Inc. and TC Energy Corporation – two utilities that Concentric specifically excluded in constructing the Canadian Holding Company proxy group. Why did Concentric not use the Canadian Proxy Group that Concentric specifically devised so as to be "comparable" to Enbridge Gas?

(b) Please explain why, in determining the averages for these variables, Concentric included the eight US utilities included in the US Holding Company sample, but also included Chesapeake Utilities Corporation and UGI Corporation – two utilities that were excluded in constructing the US Holding Company proxy group. Why not use the US Proxy Group that Concentric specifically devised so as to be "comparable" to Enbridge Gas?

5.3-IGUA-69

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Pages 106-109 of 164

Concentric discusses Gas versus Electric Risks

Questions:

(a) Please provide the total delivered gas volumes for Enbridge Gas Inc. (Reg-only) for each of 2011-2021

(b) Please provide the total delivered gas volumes related to heating load for Enbridge Gas Inc. (Reg-only) for each of 2011-2021.

(c) Please provide the cost of upgrading the electric grid to replace the Enbridge Gas Inc. (Reg-only) heating load with electric heat.

5.3 -IGUA-70

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 115 of 164

Question:

Please provide an updated Figure 42 that uses S&P data.

5.3-IGUA-71

Preamble: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 58, Paragraph 1.

The cited evidence states:

In 2020, residential customers accounted for approximately 57% of the Company's revenues but just 32% of its sales volumes.

Questions:

(a) Please complete the following table for the most recent full year for which data are available:

	% Customers	% Regulated Revenue	*% Gas Supply Revenue*	*% Storage Revenue*	*% Transmission Revenue*	*% Distribution Revenue*	% Sales Volume	% System Peak Demand
Residential		*e.g. 57%*					*e.g. 32%*	
Commercial								
Institutional								
Small Industrial								
Medium Industrial								
Large Industrial								
Electric Generation								
Other								
Total	100%	100%	100%	100%	100%	100%	100%	100%

In the event that EGI's data do not differentiate between some of these end use classes (e.g. between Commercial and Institutional), please provide data at the level of aggregation they are available.

In the event that the values on the Other row are non-zero, please identify the type(s) of customers or uses reflected on this row.

(b) Please provide the definitions EGI used to differentiate customer types in the table provided in response (e.g., to differentiate between different sizes of industrial customers).

7.0-IGUA-72

Preamble: A working version of the cost allocation model for the current rate classes is requested, to better understand the development of internal allocators and linkages across spreadsheets.

Question:

Please provide an integrated working version of the complete cost allocation study for current rate classes in MS Excel electronic format with formulae intact. Please include the derivation of revenue-cost ratios for the current rate classes. Please include derivation of all internally developed functionalization, classification and allocation factors.

7.1-IGUA-73

Preamble: IGUA would like to better understand the impact of inadequate or inconsistent information or record keeping on EGI's proposal for harmonized cost allocation for distribution assets.

References: 7.1.1 paragraph 12; 8.2.1 pages 12 to 15

Questions:

(a) Please explain how EGD tracks its distribution assets, and why it is impossible to geographically differentiate those assets.

(b) Please explain the level of detail that is available for segregating distribution assets between EGD CDA and EGD EDA.

(c) Please explain how Union tracks its North system distribution assets, and why it is impossible to differentiate costs between the North West and North East geographic zones.

(d) Please explain the level of detail that is available for segregating distribution assets between Union North West and Union North East areas.

(e) Can EGI identify its physical mains by geographic region using its GISs, such that there is a physical alternative allocation method to that advanced in paragraph 33 of 8.7.1? Please specify the level of physical detail that is available by geographic region.

7.1-IGUA-74

Preamble: Clarification regarding the classification and allocation of gas supply costs is requested.

Questions:

(a) Please detail how gas supply costs are classified into commodity, load balancing and transportation. Please include supporting workpapers for the development of the GASSUPPLY_CLASS classification factor, for the current rate classes.

(b) Please provide supporting workpapers for the development of the following allocation factors, with a definition of the specific peak demands and average demands used for each, for the current rate classes. Please indicate whether the parameters apply to gas supply service, bundled DP service, semi-unbundled service or unbundled service.

(i) LOAD_BALANCING

(ii) TRANS_FUEL

(c) For 2024 gas supply commodity costs, please specify forecast monthly volumes and costs by receipt point.

(d) From 7.1.3 Attachment 1 page 1, it appears that administrative costs for gas supply were previously allocated to both sales and direct purchase customers. Please identify the administrative costs previously assigned to direct purchase customers, and explain where those costs are proposed to be recovered.

7.1-IGUA-75

Preamble: It is IGUA's understanding that the allocation of upstream transmission/ transportation costs on a volumetric basis is historically justified by a conceptual model in which the upstream transmission facilities are operated at or near 100 percent load factor on an annual basis. IGUA seeks to confirm that condition applies to 2024.

Questions:

(a) For each upstream transmission asset/contract, please define the pipeline, the receipt points, delivery points, capacity retained, annual volumes transmitted, annual load factor and annual cost. Please indicate how the cost for each contract is classified between demand, commodity and load balancing.

(b) Please provide supporting workpapers for the derivation of the TRANS_DEMAND allocation factor, with an explanation for volumes included and excluded from the factor, for the current rate classes.

7.1-IGUA-76

Preamble: Additional detail regarding classification and allocation of storage costs is requested. **Reference 7.1.3 Attachment 1, 7.2.1 and 7.3.1, Attachments 5, 9, 10 and 12.**

Questions:

(a) Please provide the rationale for derivation of the DEL_SPACE_OPCON classification factor, and provide supporting workpapers.

(b) Please explain conceptually how storage costs are segregated between the gas cost revenue requirement and the delivery revenue requirement.

(c) Please provide the allocation of operational contingency costs to each service area in the most recent previous cost allocation studies.

(d) Please explain how the OP_CONTINGENCY allocation factor is derived, and provide supporting workpapers, for the current rate classes.

(e) Re EGI storage demand deliverability at 7.1.3 Attachment 1 page 2, please define the term “design day demands less design day deliveries” for the purposes of allocating these costs.

(f) Please provide supporting workpapers for the derivation of the NETFROMSTOR allocation factor, for the current rate classes.

(g) Please explain why storage deliverability costs are not allocated based on the difference between design day demands and average day demands.

(h) Please provide supporting workpapers for the derivation of the STORAGEXCESS allocation factor, including monthly volumes by class, for the current rate classes.

(i) Please provide workpapers for the development of the STORCOMM allocation factor.

7.1-IGUA-77

Preamble:

IGUA requests clarification of the proposed cost allocation treatment of the Panhandle transmission system and the St. Clair transmission system.

In previous proceedings EGI (and previously Union Gas) acknowledged an inequity in allocating significant Panhandle System expansion costs to customers served off of the St. Clair System and who do not derive any benefit from the Panhandle System. Previous Union gas proposed cost allocation changes to remedy this inequity, however consideration of those changes was deferred by the OEB to a review of EGI’s entire cost allocation methodology. IGUA seeks to understand how EGI’s proposal in this proceeding addresses this inequity.

References: 7.1.4 Section 1.1 paragraphs 9-18; 7.2.1 Attachments; 7.3.1 Attachments

Questions:

(a) Please explain why and how Panhandle/St. Clair costs are segregated between the gas cost revenue requirement and the delivery revenue requirement in 7.2.1 Attachments 9 and 10.

(b) Is it generally correct that, under design conditions, the only customers who benefit from the Panhandle and St. Clair systems are those west of Dawn? Please explain your response.

(c) Please provide design day demands for customers west of Dawn for each current rate class, split between those served from the Panhandle system and those served from the St. Clair system.

(d) Please explain how EGI’s proposal eliminates the inequity detailed in the preamble, namely that customers situated on the St. Clair pipeline are being allocated costs

associated with the Panhandle System expansion. Please include a quantitative demonstration in your response of how the allocation of Panhandle System expansion costs will change under your proposal.

(e) Paragraph 15 of 7.1.4 Section 1.1 appears to indicate that costs are allocated to all in-franchise bundled rate classes based on design day demands. Please explain how design day demands are derived for the bundled rate classes in the PAN-STCLAIR allocator. In particular, please explain why the design day demands in 7.2.1 Attachment 12 generally appear to be approximately 30 percent of class design day demands, except for Union North Rate 20 and Union South rates T1, T2 and T3.

(f) Paragraph 14 of 7.1.4 Section 1.1 appears to indicate that the allocation method for Panhandle/St. Clair is based on a single rate zone model. Please reconcile this position with the proposed zone-specific transportation charges for harmonized rates, notably the South zone charge for Rate E24 and the eligibility restrictions for Rate E20.

(g) Please provide a version of 7.2.1 Attachment 6 with costs for the Panhandle and St. Clair systems classified separately.

(h) Please provide supporting calculations for the derivation of the values shown at 7.1.4 Attachment 1, column (a).

7.1-IGUA-78

Preamble:

Clarification regarding the proposed changes to the allocation of the Dawn-Parkway costs is requested.

References: 7.1.4 Section 1.4; 7.2.1 Attachments; 7.3.1 Attachments

Questions:

(a) Please describe the specific rationale for the nature of the D-PTRANS allocator and provide supporting calculations for its development. As part of your response:

(i) For bundled in-franchise customers, please specify which customers' demands are and are not included in the allocator.

(ii) For semi-unbundled and unbundled customers, please explain what is meant by the respective service area and indicate which customers' demands are and are not included in the allocator.

(b) Please explain why a distance-weighted allocator is appropriate for these costs, in the harmonized cost allocation/rate design framework posited in this application.

(c) Please provide supporting calculations for the derivation of the values shown at 7.1.4 Attachment 1, column (d).

7.1-IGUA-79

Preamble: Additional information regarding the allocation of Parkway station costs is requested. **Reference 7.1.4, Section 1.2.**

Questions:

(a) Please explain why Parkway station costs for measurement and compression are not separately classified and allocated. Please provide the costs for each function.

(b) Please provide supporting calculations for the PKWY_DEMAND allocator, the current rate classes.

(c) Are Parkway compression costs allocated to all in-franchise customers based on design day demands, including those west of Parkway? Please explain your response.

(d) Please explain how bi-directional design day demands are derived for each rate class, and provide supporting workpapers. Please also explain how demands in opposite directions can both contribute to cost causation on a design day at the Parkway station.

(e) Please provide supporting calculations for the derivation of the values shown at 7.1.4, Attachment 1, column (b).

7.1-IGUA-80

Preamble: Clarification regarding allocation of costs for Dawn station is requested. **Reference 7.1.4, Section 1.3.**

Questions:

(a) Please explain whether EGI incurs compression costs at Dawn associated with westerly flows under design conditions. If so, please explain why Dawn compression costs are assigned to Dawn Parkway.

(b) Please identify the customer demands that are included in the DAWN_DEMAND allocation factor and provide supporting workpapers for the development of the allocator.

(c) Please explain why the bi-directional design day demands in the DAWN_DEMAND allocator are about 71 percent of distribution design day demands, except for Union North Rate 20 and Union South rates T1, T2 and T3.

(d) Please provide supporting calculations for the derivation of the values shown at 7.1.4 Attachment 1, column (c).

7.1-IGUA-81

Preamble:

Costs for high pressure mains over 4" represent a significant cost to IGUA's members in the proposed cost allocation studies. EGI's proposed method for allocating these costs appears to be based on design day demands for customers taking service at distribution pressure. No attempt appears to be made to directly assign these costs to large customers who are sole use or who rely only on relatively short mains.

Reference 7.1.3 Attachment 1, Distribution Demand, Line No. 1; 7.2.1 Attachments; 7.3.1 Attachments

Questions:

(a) For the most recent cost allocation study for Union North, please provide the net book cost for mains over 4" split between sole use, joint use and grid categories. Please also provide the mains cost allocation details.

(b) For the most recent cost allocation study for Union South, please provide the net book cost for mains over 4" categorized as other transmission and distribution. Please also provide the allocation of the costs for these mains to Union South customers.

(c) For each of the current rate classes, please provide the number of customers and design day demand for customers taking service directly from high pressure mains over 4" for each class.

(d) Please provide supporting detail and workpapers for deriving the ZERO_INT classification factor at 7.2.1 Attachment 7 and 7.3.1 Attachment 7.

(e) Please provide supporting detail for the derivation of the HIGHPRESS>4 allocator, at 7.2.1 Attachment 12 and at 7.3.1 Attachment 12.

(f) For each customer that will be eligible to take service under harmonized rate E20, E22 or E24, please provide the mains distance in metres/kilometres between the customer's location and the transmission gate station.

(g) Please also provide total kilometres of high-pressure mains over 4" for each current service area.

(h) Reference 7.1.3 Attachment 1. Please explain whether the allocation of mains costs to sole use customers in the Union North zone represented all mains costs for those customers, or whether those customers' loads were included in the allocation factor for joint use mains. Please also explain why that approach was not retained and expanded to other zones in the proposed cost allocation study.

7.1-IGUA-82

Preamble: A significant share of distribution and transmission costs are allocated using some measure of design day demand. IGUA requests a primer on how those demand allocators are derived, and when the methods were approved by the Board.

Questions:

(a) Please detail the methodology used to develop design day demands in each of the current service areas, and when those methods were approved by the Board. Please distinguish between general service and contract service.

(b) Please specify any differences in defining design day demands across the current service areas and explain how they were reconciled in the current proposal.

(c) Please indicate how design day demand conditions are derived, how frequently they are updated, and when they were approved by the Board.

(d) Where design day demands for interruptible customers are included in allocation factors, please specify how those demands are derived and the basis for that approach.

(e) Please provide supporting workpapers for the development of each design day demand allocator, including but not limited to ALBIONTRANS, DAWN_DEMAND, HIGHPRESS>4, HIGHPRESS<4, KIRKWALL_DEMAND, LOWPRESS, PAN_STCLAIR, and PKWY_DEMAND.

7.1-IGUA-83

Preamble: IGUA seeks clarification regarding the treatment of DSM costs. **Reference 7.2.1 Attachments; 7.1.4 Section 5 and Attachment 1; 7.2.3 paragraph 75.**

Questions:

(a) Please provide a five-year history of budget and actual DSM costs by rate class, based both on the current class definitions.

(b) Are variances in the DSM budgets tracked and recouped/refunded on a class-specific basis? Please explain as necessary.

(c) Please reconcile the DSM administration costs between 7.2.1 Attachment 7 ($30,707) and 7.2.1 Attachment 8 ($62,581).

(d) Please provide a copy or reference to the Company's DSM plan that supports budget values used for the development of the DSM_PRO and DSM_ADM allocators, as discussed at 7.1.4 section 5.

(e) Is it correct that the rate impacts in 7.1.4 Attachment 1 related to DSM result from a change in budgets by class, and not a methodological change? Please explain any negative response.

(f) Please indicate where and how the low-income customer DSM costs are allocated, as reported at 7.1.2 paragraph 75.

7.1-IGUA-84

Preamble: IGUA requests additional detail regarding allocated meters costs.

Reference 7.1.2 and 7.1.3 Attachment 1.

Questions:

(a) Please provide supporting workpapers for the allocation of meters costs based on replacement cost, as indicated at 7.1.2 paragraph 79, for the current rate classes.

(b) Please provide results from the most recent full cost of service study for each of the three current service territories for meters allocation by rate class, as discussed at 7.1.3 Attachment 1 page 6.

7.1-IGUA-85

Preamble:

IGUA requests detail regarding how station costs are identified and allocated.

Reference 7.1.3 Attachment 1 and 7.2.1

Questions:

(a) Reference 7.1.3 Attachment 1 page 6: Please provide the allocation of station costs by current rate class from the most recent cost allocation study for the three existing rate areas.

(b) Please provide supporting workpapers for the development of the STATIONREPLCOST allocator, for the current rate classes.

(c) Reference 7.2.1 Attachment 7: Please explain how the station costs were identified within the M&R detail and explain why those costs are not recorded in the customer stations account.

(d) Please provide book net plant for customer stations by current rate class, including costs recorded in both the measuring and regulating and the customer stations accounts.

7.1-IGUA-86

Preamble:

EGI forecasts some $11.1 million in costs associated with the Large Volume Customer Care account. IGUA requests detail regarding the nature of costs associated with that account, and the basis for the allocation of those costs.

Reference 7.1.3 Attachment 1 page 6, 7.2.1 Attachment 9.

Questions

(a) Please provide a listing of the specific services provided to customers that are associated with the Large Volume Customer Care account.

(b) Please provide a history of the number of employees engaged in providing those services for each operating area over the past five years, and as forecast for 2024.

(c) In the most recent cost allocation study for the individual service areas, please provide the allocation of these costs.

(d) Please discuss whether employees are assigned to individual customers. If so, please provide the number of employees assigned to customers in each rate class.

7.1-IGUA-87

Preamble:

Clarification regarding allocation of UFG and company-use gas costs is requested.

Reference 7.1.2, 7.2.1 Attachments

Questions:

(a) Reference 7.1.2 paragraph 12: Please explain how UFG and company-use gas costs are functionalized.

(b) Please identify the specific uses for company-use gas, the volumes associated with each use (as available), and the locations for the consumption (as available).

(c) To the extent available, please provide functionalized UFG rates (UFG volumes per total volume) and costs by current operating area and in total.

(d) Please provide supporting workpapers for the derivation of the STORCOMM allocator, including an explanation for how injection and withdrawal volumes for the bundled in-franchised classes are determined.

(e) Please provide supporting workpapers for the derivation of the TRANSCOMM allocator. Please include an explanation for the reference to “delivery and transportation volumes”

at 7.2.1 Attachment 11 page 14. Please also explain why costs associated with this allocator are not assigned to unbundled customers.

(f) Are any customers interconnected directly to the transmission system? If so, are volumes associated with those customers excluded from the DISTCOMM allocator? Please explain as necessary.

(g) Please provide supporting workpapers for the derivation of the DISTCOMM allocator.

(h) Are customers taking service directly from the high pressure distribution system assigned the same UFG rate as those customers who rely on both the high pressure and low pressure distribution systems? If so, please explain.

8.2-IGUA-88

Preamble:

IGUA seeks to understand the bill impact of the proposed rate changes for the contract rate classes, for the period in which existing rate classes remain in effect (2024 and 2025).

Reference 8.2.6; 8.2.8.

Questions:

(a) Please provide a histogram for the distribution of bill impacts on each current rate class by customer size associated with the rate changes effective in 2024. To the extent practical, please provide the impact evaluation by rate class decile (i.e., average percent increase for the 10 percent of customers with the smallest load, the average percent increase for the next 10 percent, etc.)

(b) Please show the calculations for each rate class in 8.2.6 Table 4.

(c) Regarding the impacts shown at 8.2.6 Table 4, please reconcile the “excluding rate riders” bill impact with the average percentage changes shown at 8.2.8 Attachments 1 and 2, for the following rate classes: EGD 6, 110, 115, 135, 170; Union North 20, 25, 100, Union South T1, T2, T3.

8.2-IGUA-89

Preamble:

IGUA requests details regarding the mapping of allocated costs to rate design revenue requirements, for the current rate classes.

Reference: 7.2.1 Attachments 8, 9 and 10, 8.2.8 Attachments 1 and 2; 7.3.1 Attachments 8, 9 and 10, 8.2.9 Attachments 1 and 2.

Questions:

(a) Please provide a mapping from the costs reported at 7.2.1 Attachment 8 to the revenue requirements reported at 8.2.8 Attachment 1, including the split between delivery and gas supply. Please include an explanation for any calculations required in the procedure.

(b) Please provide a mapping from the costs reported at 7.2.1 Attachment 8 to the revenue requirements reported at 8.2.8 Attachment 2. Please include an explanation for any calculations required in the procedure.

8.2-IGUA-90

Preamble: Reference 8.2.8 Attachment 2, proposed EGD Zone Rate 110

Questions

(a) Please identify the components of customer-related costs that vary with customer size in Rate 110 and justify setting the customer charge at 28 percent of customer-related costs. Please include supporting calculations.

(b) For Rate 110, please provide number of customers, annual volumes and design day demands (as available) segregated by main attachment category (high pressure over 4", high pressure at or below 4", low pressure).

(c) If smaller customers in this class are more likely to be attached to the low-pressure mains system, please explain whether a declining block demand charge would be appropriate.

(d) Please provide the rationale and the quantitative basis for the rate differential in the current declining block volumetric delivery charges.

8.2-IGUA-91

Preamble: Reference 8.2.8 Attachment 2, proposed EGD Zone Rate 115

Questions:

(a) Please identify the components of customer-related costs that vary with customer size in Rate 115 and justify setting the customer charge at 28 percent of customer costs. Please include supporting calculations.

(b) For Rate 115, please provide number of customers, annual volumes and design day demands (as available) segregated by main attachment category (high pressure over 4", high pressure at or below 4", low pressure).

(c) If smaller customers are more likely to be attached to the low-pressure mains system, please explain whether a declining block demand charge would be appropriate for this class.

(d) Please provide the rationale and the quantitative basis for the differential for the current declining block volumetric delivery charges.

(e) Please explain generally why the demand-related cost per unit of contract demand is substantially lower for the EGD Zone Rate 115 class than it is for the EGD Zone Rate 110 class.

(f) Please explain generally why the commodity-related cost per unit of billed volume is substantially lower for the EGD Zone Rate 115 class than it is for the EGD Zone Rate 110 class.

8.2-IGUA-92

Preamble: Reference 8.2.8 Attachment 2, proposed EGD Zone Rate 135 (Seasonal)

Questions:

(a) Please explain how allocated costs are seasonalized into the reported revenue requirements.

(b) Please explain when and how the current declining block volumetric charge differentials were established.

(c) Please explain why disproportionately large rate increases are assigned to the second and third volumetric block charges for both seasons.

(d) Please explain the basis for the delivery rate adjustment in 8.2.8 Attachment 1 column (g) for this class and explain how it is reflected in the rates proposed for 2024 and 2025.

8.2-IGUA-93

Preamble: Reference 8.2.8 Attachment 2, proposed EGD Zone Rate 170

Questions:

(a) Please detail how contract demand levels are determined for large interruptible customers, and explain what they represent.

(b) Please state when the current declining block volumetric charge differentials were established, and the basis for the charge differentials.

(c) Please explain why EGI proposes to eliminate the declining block volumetric charge differentials.

(d) Please explain how curtailment credits are derived, and how they are reflected in customer bills.

(e) Please explain the "10583%" reported unit revenue change (page 4, line 112) for delivery revenues between current and proposed rates for this class in 8.2.8 Attachment 2.

(f) Please reconcile the total delivery revenue values shown in Attachment 2 for Rate 170 to those shown in Attachment 1.

8.2-IGUA-94

Preamble: Reference 8.2.8 Attachments 1 and 2, 8.2.7 Attachment 1; proposed Union North Zone Rate 20

Questions:

(a) Please identify the components of customer-related costs that vary with customer size in Rate 20 and justify setting the customer charge at 38 percent of customer costs. Please include supporting calculations.

(b) Please explain when the declining block contract demand charge differentials were established, and then provide the quantitative basis for the differentials.

(c) Please explain when the declining block volumetric charge differentials were established, and then provide the quantitative basis for the differentials.

(d) Please explain why EGI proposes to eliminate the volumetric block charge differential.

(e) Please explain the distinction between Commodity Transportation 1 and Commodity Transportation 2 and explain why the Commodity Transportation 2 volumes appear to currently be assigned a zero charge in 8.2.8 Attachment 2.

(f) Please explain the difference (if any) between the reference to unbundled storage service in 8.2.8 Attachment 2 and bundled (T-Service) Storage Service Charges in the proposed handbook at 8.2.7 Attachment 1 page 49.

(g) Please explain the basis for the delivery rate adjustment in 8.2.8 Attachment 1 column (g) for this class and explain how it is reflected in the rates proposed for 2024 and 2025.

8.2-IGUA-95

Preamble: Reference 8.2.8 Attachment 2, 7.2.1 Attachment 12; proposed Union North Zone Rate 25

Questions:

(a) Please reconcile the bill count for Rate 25 with the reported 4 customers for the class in 7.2.1 Attachment 12. Are customers being assigned a customer charge that are not counted for cost allocation?

(b) Please explain why this rate category does not have a demand charge, as do the other interruptible service options.

(c) Please define the MAV charge and how the cost basis for that charge is derived.

8.2-IGUA-96

Preamble: Reference 8.2.8 Attachment 2, proposed Union North Zone Rate 100

Questions:

(a) Please identify the components of customer-related costs that vary with customer size in Rate 100 and justify setting the customer charge at 34 percent of customer costs. Please include supporting calculations. Please explain why the proposed customer charge is reduced.

(b) Is it correct that all Rate 100 customers balance their deliveries to the distribution city gate with their consumption on a daily basis, within the tolerances allowed by EGI, and are therefore assigned no EGI storage or transmission costs? Please explain any negative response.

8.2-IGUA-97

Preamble: Reference 8.2.8 Attachment 2, proposed Union South Zone Rate M4.

Questions:

(a) Is it generally correct that the premium for the first block contract demand charge (firm) is intended, at least in part, to recover customer-related costs, as the rate class has no customer charge? Please explain any negative response.

(b) Please provide supporting calculations for the magnitude of the first block charge premium related to the recovery of customer-related costs.

(c) Please provide the customer-related revenue requirement for Rate M4 consistent with the method applied to other rate classes in 8.2.8 Attachment 2.

(d) Please provide the rationale for including firm delivery contract demand charge block differentials in this tariff, and provide the quantitative basis for the differentials.

8.2-IGUA-98

Preamble: Reference 8.2.8 Attachment 2, proposed Union South Zone Rate T1

Questions:

(a) Please provide the basis for the current transportation contract demand block charge differentials.

(b) Please explain generally why the interruptible volumetric charge is reduced by 85 percent for proposed rates. Please include an explanation for why the current charge appears to substantially exceed the allocated cost.

8.2-IGUA-99

Preamble: Reference 8.2.8 Attachment 2, proposed Union South Zone Rate T2

Questions:

(a) Please provide the range of customer sizes within Rate T2, in terms of contract transportation demand. Please provide average customer demand by decile.

(b) Please provide the basis for the large reduction in the proposed customer charge. Are the customer-related costs for any customer in the class at or below $3,000 per month?

(c) Please provide the basis for the current transportation contract demand block charge differentials.

(d) Please explain generally why the interruptible volumetric charge is reduced by 49 percent at proposed rates. In particular, please explain why the current charge appears to substantially exceed the allocated cost.

(e) Please describe the factors leading to the proposed large increases to the unbundled storage charges, for both Rates T1 and T2.

(f) Please describe the factors leading to the large proposed increases in customer supplied fuel rates, for both storage and transportation, for both Rates T1 and T2.

9.1-IGUA-100

Preamble: Exhibit 9, Tab 1 Schedule 1 Attachment 1

Questions:

(a) For each deferral and variance account listed in this Attachment, please provide the date on which the account was created.

(b) Please list all deferral and variance accounts that were in effect in 2012 for Enbridge Gas Distribution and for Union Gas, along with the dates on which each of those accounts were created.

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