INTRODUCTION

The Federation of Rental-housing Providers of Ontario (FRPO) appreciates the opportunity to assist the Board in its consideration and determination of this landmark case. The scale and scope presented a challenge not the least of which was for the Panel of Commissioners providing the appropriate scoping of issues, steps of discovery while balancing regulatory efficiency. We appreciate the considered and informative procedural orders and the active and engaged adjudication that was evident in this proceeding.

In addition, FRPO would like to acknowledge the ratepayer representatives with whom we started our collaboration on this proceeding prior to the initial submission of evidence. From the communication shared to the enhance understanding of issues and perspectives at the outset, to the allocation of labour to content experts, to the considerate and respectful re-allocation of time for discovery in not only the hearing but also the pre-hearing conferences, in our respectful submission, Ontario was well-served.

This collaboration extends to this final stage of written submissions where multiple drafts were shared amongst parties allowing for an efficient and we trust effective provision of the stakeholders' interests. Through this last process, we have sought to assist but also lean on those with subject matter leads in an effort to further those interests of efficiency and effectiveness. In doing so, we will note where we adopt the submissions of our lead representatives after a considered engagement. In doing so, we want to specifically acknowledge and thank the School Energy Coalition (SEC) representatives who took a lead role in many aspects of this proceeding.

In respect of the structuring of this proceeding through the Board approved Issues List, our submissions follow the list in a similar fashion used by Board staff. If we do not either submit FRPO's views or specifically adopt those of our colleagues that does not infer that we agree with the applicant's proposal. Our lack of comment means we want to allow those with better informed views to engage the issues with the utility in a manner that is helpful to the Board.

1) Are the proposed rates and service charges just and reasonable?

FRPO respects the fact that the Board has allowed the phasing of this very large and complex proceeding. The true test of just and reasonable likely requires the completion of all phases of the proceeding. FRPO submits that the approval of the Settlement proposal, the allowance for discovery and the engagement of the panel provides a solid foundation for the just and reasonableness of the initial 2024 rates.

2) Have the customer benefits identified in the amalgamation proceeding EB-2017-0306/0307 been realized having regard to the five-year deferred rebasing term that was approved?

FRPO is concerned that the distribution of benefits from the five-year deferred rebasing term were decidedly one-sided. EGI has increased Operating Costs in spite of claims of savings from integration. We note that EGI provided an avoided cost analysis to support its claims of integration savings.[1] On the other hand, this type of analysis can never be fully tested. We would have more to say about our concerns in this area, but the Settlement Proposal addressed O&M in a negotiated fashion, reducing some ratepayer risks. In our view, we have some concerns about the sustainability of savings asserted by the company particularly in the area of moving to "As a Service" Model.

Lastly our biggest on-going concern is value for money. In spite of EGI promoting its investment in moving to one billing system for all its customers, what customers have experienced was missed reads, billing issues and lack of responsiveness from the company once issues were identified.[2] EGI's response has been the Assurance of Voluntary Compliance followed by a request to lower the bars of performance. In an age where technology ought to be able to drive improvement, EGI is seeking relief from standards that they regularly reached before the merger. With performance like this from EGI's integration efforts, FRPO can state that we have not seen the customer benefits identified in the amalgamation proceeding.

3) **Has Enbridge Gas appropriately considered energy transition and integrated resource planning in relation to such things as:**

a) load forecast

b) deemed capital structure

c) depreciation rates

d) forecast capital expenditures

e) allocation and mitigation of risk to determine new rates that will be effective January 1, 2024, considering relevant government policies and legislation?

FRPO appreciates the investment of time in discovery and articulation of shared concerns along with the level of insight provided by SEC in their submissions regarding Energy Transition. We fully support their submissions and will not try to repeat those thoughts in our own words.

[1] Exhibit JT1.9
[2] EB-2022-0110 Exhibit I.FRPO.20 to FRPO.28

4) Has Enbridge Gas appropriately considered the unique rights and concerns of Indigenous customers and rights holders in its application?

We learned more about the unique rights and concerns in the Settlement discussions which include contributions from Indigenous representatives. In learning about these issues, we are concerned that the very presence of multiple representatives, representing multiple indigenous interests speaks to their views on whether the application has appropriately addressed their rights and concerns. Respectfully, though, while FRPO supports indigenous rights and concerns, we believe it is most appropriate that their authorized representatives speak for their clients.

5) Has Enbridge Gas identified and responded appropriately to all relevant OEB directions and commitments made from previous proceedings?

EGI provided a summary of Directives and Commitments on page 1 of its Exhibit 1, Tab 13, Schedule 1 which was helpful in understanding the reference for follow-up on items accumulated from the previous legacy utilities and the merged utility.

While EGI complied with the directive on accounting for the PDO shift during the deferred rebasing period as we will explain under Issue 18 f) where the critical analysis is focused on the end of the legacy utility IRM period of Dec. 31, 2018 and the initiation of the merged utility's deferred rebasing period.

A. Rate Base

6) Is the 2024 proposed rate base appropriate?

7) Is the forecast of 2024 capital expenditures underpinned by the Asset Management Plan, and in-service additions appropriate?

One of the directives from the merger proceeding was the production of a consolidated asset management plan (AMP) to support any Incremental Capital Module (ICM) request for 2021.[3] EGI produced this document in their application for 2021 rates.[4] Upon initial review of the AMP, FRPO was encouraged that EGI seemed to be adding some quantifiable rigour through the implementation of a new asset investment planning tool, Copperleaf C55. However, we were surprised and concerned that the

[3] EB-2017-0306/0307 Decision and Order, August 30, 2018, pg. 33-34
[4] EB-2020-0181 EGI_APPL_Phase 2_20201015, Exhibit C, Tab 2, Schedule 1

budgets for both system access and renewal for the 5 years planned were more than double the previous five years resulting in our request for a Technical Conference. [5]

The resulting technical conference provided ratepayer representatives with a better understanding of the new process aided by the software. Through significant discussion at the technical conference, it was clear that the process of using the software was still evolving. However, we were left concerned that the iterative process of "optimizing" the budget spending seemed to be an exercise in maximizing the amount of capital that could be budgeted and spent.[6]

Our concerns have not been allayed in watching spending continue to increase including the forecasts included in this application. We attempted to pursue understanding how the value framework has been applied in capital spending through discovery[7] but it continued to be a nebulous as opposed to rigorous process. This perception seemed to crystallize as SEC was asking questions regarding the capital planning process and the changes made in the Capital Update.[8]

While we will make some specific additional submissions that we believe will be helpful to the Board, our collaboration with SEC afforded us a preview of an early draft which presents a compelling, principled argument supported by substantial specific evidentiary references. In respect of this excellent summary and for efficiency , FRPO endorses and adopts SEC's argument with respect to the 2024 rate base and links to the Asset Management Plan.

Our additional submissions are as follows:

<u>Asset Management would be Improved with Incentives Tied to Extending Asset Life</u>

As the Board is aware, the Settlement Proposal increased the proposed spending on an Enhanced Distribution Integrity Management Program (EDIMP). The agreement between the parties was premised on the annual reporting. From a ratepayer perspective, this reporting would describe what facilities work was deferred or avoided or otherwise impacted as a result of the EDIMP work.[9] This reporting will hopefully demonstrate a value for money for the additional diagnostics, analysis and resulting capital savings. In our view, this opportunity would be reinforced with the addition of a

[5] EB-2020-0181 FRPO_EGI ICM_REQ TECH CONF_20210128 esigned
[6] EB-2020-0181 FRPO_SUB_EGI 2021 RATES P2_20210314, pg. 3
[7] Exhibit I.2.6-FRPO- 45,46 and 52
[8] Transcript_Oral Hearing_Vol 11_Enbridge Gas Rebasing_20230731, pages 120-150
[9] EGI_SettlementP_2024 Rebasing_20230713, Issue 32, pg.56

category of asset service life extension in the scorecards tied to incentives for EGI leadership.

In the oral hearing, through a challenging discourse that may have been unduly complicated by lack of precision in corporate structure, we tried to explore the concept with EGI's vice-president.[10] We wanted to ask EGI's senior leadership, as opposed to the Capital Panel, since we firmly believe that fundamentally organizations follow incentives. Upon review of the references provided[11] and confirmation provided by the witness[12], there are management incentives tied to EBITDA which includes growth capital.

In our view, there is clear need and opportunity for the company to adjust its paradigm on the traditional utility bias toward invested capital is good and necessary for the enhancement of utility earnings. With direction from the Board in this proceeding, the utility ought to be considering the risk of stranded assets and ultimately the potential for an evolution in their assumption on who should bear that cost.[13] In the interim though, the opportunity is there to consider incentives associated with extending service life of an asset.

Given Guidehouse's international operations, we had hoped that some efforts or case studies from Europe would yield some insight on regulatory approaches to incent utilities to extend the service life of assets.[14] The resulting undertaking response provided by Guidehouse indicated that it was "not aware of any utilities with specific metrics incentivising asset life."

Respecting that answer and the context, FRPO offers a reference to a significant study sponsored by the Agency for the Cooperation of Energy Regulators (ACER) and conducted by DNV and Trinomics. With Europe grappling with the same issues of Energy Transition as it pertains to asset life, this study provides a comprehensive review of regulatory aspects to respond to energy transition:[15]

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[10] Final Transcript EB-2022-0200 Enbridge Gas Rebasing Vol 1, pg. 110-126
[11] Exhibit I.1.2-SEC-79 Attachment 1, page 3 and Exhibit JT1.8 Attachment 1
[12] Final Transcript EB-2022-0200 Enbridge Gas Rebasing Vol 1, pg. 118 and 120
[13] Final Transcript EB-2022-0200 Enbridge Gas Rebasing Vol 4, pg. 89, lines 5-14, Ms. Giridhar affirms EGI's views on ratepayer responsibility as a result of the regulatory compact.
[14] Final Transcript EB-2022-0200 Enbridge Gas Rebasing Vol 1, pg. 127-130
[15] ACER, Future Regulatory Decisions on Natural Gas Networks: Repurposing, Decommissioning and Reinvestments, Executive Summary found at https://www.acer.europa.eu/events-and-engagement/news/acer-publishes-study-future-regulatory-decisions-natural-gas-networks

> *The key objective of this assignment is to perform a study on the regulatory challenges, the current regulatory practice, and possible regulatory options in relation to repurposing, decommissioning, reinvestments, and the extended use of natural gas transmission assets beyond their regulatory asset lifetime.*

While FRPO understands that there is not enough evidence on the record to make specific recommendations on this topic, we found the study presented Regulatory Options and Recommendations that could form the basis for consideration of how the utility could incented to extend asset service lives.[16]

A Better Understanding of the Contractor Alliance is Warranted

One of FRPO's concern during the deferred rebasing period has been the sole sourcing and awarding of large contracts to a contractor in EGI's Distribution Alliance. Our concern at a very high level is the difficulty in demonstrating value especially when incentives are not engaged to protect ratepayer interests.

Through our efforts to understand this process better, we received a response to our Technical Conference questions and the undertaking "To explain further how the alliance partnership construct benefits ratepayers" and provide the following excerpt:[17]

> *The Alliance contract employs a number of components that drive the effective spend in this area:*
> *a) Target profit margins are set with a sharing mechanism to balance risk and reward.*
> *b) Balanced scorecard manages performance which uses key performance indicators to incent productivity while aligning Enbridge Gas strategic goals in Safety, Quality, and Customer Satisfaction.*
> *c) There is a 1% productivity savings target based on the revenue associated with the annual volume of work that is used to promote innovation and drive efficient execution of work.*

Having led a natural gas utility for over ten years and having served seven years on the Advisory Council for the TSSA, I understand the importance of having qualified contractors performing work on natural gas infrastructure. The above components may

[16] Ibid, pg. 163-177
[17] Exhibit JT5.45

provide some aspects of effective spend especially on "day-to-day" traditional efforts by the contractors (e.g., installing residential mains, services and meters, etc.). However, our concern is for large replacement projects that do not have an economic test from a cost-benefit analysis, there does not seem to be a driver to ensure value for money.

From 2020 to 2021, EGI incurred an average spend of over $0.5 billion for contractors in EGI's distribution alliance.[18] In addition, and this is our greatest area of concern, large replacement projects, some over $100 million, are being awarded without a competitive bid process.[19] These projects have unique scope which need to be estimated individually and there is usually little frame of reference. Since there is no need to meet an economic test, it is within the discretion of the estimator to ensure sufficient budgeted funds by adding conservatisms into the assumptions. With neither the company nor the contractor bearing significant negative consequences for too high of an estimate but being rewarded for increased installation costs, there would be a natural bias to estimate high and little incentive to drive cost savings. Even if the 1% productivity savings is applied on these projects, that quantum is not, in our view, a substantial incentive to drive cost containment especially on projects of over $100M.

Given the technical and commercial difficulty of "looking under the hood" of this Distribution Alliance, we chose not to pursue further understanding at the oral hearing with the time constraints and other important items. On the other hand, FRPO is still concerned that this practice does not have economic drivers nor Board oversight that would contribute to cost containment and value for money. As we have no specific recommendations, we wanted to highlight these concerns specifically as we believe further due process is needed to ensure the EGI practices are appropriate in the public interest.

<u>RNG Spending Should Not be Driving 2024 Capital Request</u>

In preparing our submissions, we noted a substantial increase that alluded our notice previously. In its July 6th capital update, EGI has proposed a $90M increase due to "customer driven RNG injection and CNG projects."[20] FRPO is very concerned about the quantum of increase (almost 3x the prefiled evidence level[21]) and the need for this

[18] JT4.23
[19] JT7.22
[20] Updated Exhibit 2, Tab 5, Schedule 3, Page 35, item m)
[21] Exhibit 2, Tab 5, Schedule 3, Page 33 line 41

capital to be funded by ratepayers. On the second point, from the one recent major RNG project that prompted a Leave-to-Construct,[22] EGI emphasized that there is no ratepayer burden which we understood to be the case for all RNG projects (as it is for traditional natural gas producers). For ease of the reader, we provide the excerpt from our inquiry in that application:[23]

> *Preamble:*
>
> *Given that this contract may be a precedent agreement for future RNG projects, we would like to understand how the revenues and costs were analyzed for the purposes of establishing the Prepayment/Aid-to-Construction.*
>
> *Question:*
>
> *Were revenues associated with M13 or C1 rates forecasted for the customer included for the purposes of off-setting the cost of the project on a discounted cash flow basis?*
>
> ***Response***
>
> *As stated in Exhibit E, Tab 1, Schedule 1, page 3, Waste Connections has elected to pay the full capital cost of the Project through an upfront CIAC payment, resulting in a net investment of $0.0 million. As such, a Net Present Value or Profitability Index calculation is not required for the Project.*
>
> *Forecasted revenues were not included for the purposes of offsetting the cost of the Project.*

In our view, given what EGI has put on the record in the LTC application, we do not understand why ratepayers would be asked in fund this capital in 2024 rates when the customer is responsible to pay all of the facilities as opposed to utility invested capital. Beyond the reductions requested by SEC, we respectfully submit that EGI separate out utility expenditure, perhaps for CNG, or eliminate this line item from the 2024 capital.

8) Are the proposed harmonized indirect overhead capitalization methodology and proposed 2024 overhead amounts appropriate?

FRPO adopts the submissions of SEC as they pertain to the issue of Indirect Overhead capitalization.

[22] EB-2022-0203
[23] EB-2022-0203 Exhibit I.FRPO.9

B. Load Forecast and Revenue Forecast

9) Is the 2024 volume forecast by rate class and resulting revenue forecast appropriate? Is the 2024 storage and transportation revenue and upstream transportation optimization forecast appropriate?

The Settlement Proposal settled these issues with the exception of the Volume Variance Account which we address under Issues 32 and 33.

10) Is the 2024 other revenue forecast appropriate?

The Settlement Proposal settled these issues with the exception of Settled with exception of Properties and NGV. We support and adopt the submissions of SEC on the disposition of property. We provide our submission on NGV under Issue 34.

11) Are the proposals for harmonized load forecasting methodologies (heating degree days, average use, weather normalization, heat value, customer additions) and the 2024 Test Year results from those methodologies appropriate?

These issues are deferred to phase 3

C. Operating Expenses

12) Are the proposed 2024 Test Year operating and maintenance expenses appropriate?

13) Are the 2024 proposed compensation related costs (including, FTEs, wages, salaries, benefits, incentives, overtime, pension and OPEB costs) appropriate?

14) Are the 2024 proposed shared services and corporate services costs appropriate, including the proposed Centralized Functions Cost Allocation Methodology (CFCAM)?

Issues 12, 13 & 14 were conjoined for the purposes of settlement and agreed upon in the proposal with the exception of Overhead Capitalization which is its own issue #8.

15) Are the proposed harmonized depreciation rates and the 2024 Test Year depreciation expense appropriate?

16) Are the proposed 2024 Site Restoration Costs appropriate, and should the OEB establish a segregated fund for the Site Restoration Costs?

FRPO respects and appreciates the investment made by IGUA to lead and test evidence regarding depreciation. Further, with our collaboration with IGUA, we reviewed an advanced copy of their extensive and considered submissions especially with regard to different viewpoints opined by the experts. FRPO supports and adopts the IGUA submissions for these issues.

17) Are the proposed 2024 income and property tax expenses appropriate?

Settled in the Settlement Proposal.

18) In relation to the 2024 Test Year gas cost forecast,

a) Is the 2024 gas supply cost, including the forecast of gas, transportation and storage costs, appropriate?

Settled subject to Load Balancing determinations in Phase 2.

b) Is the proposal for a common reference price methodology to set gas costs appropriate?

Issue deferred to Phase 3.

c) Is the proposed harmonized approach to determining gas costs (design day, operational contingency space, unaccounted for gas, Parkway Delivery Obligation) appropriate?

Most of this issue was moved to later phases except for the Agreement on the proposal for design day and design hour.

d) Is the 2024 Test Year forecast volumes of unaccounted for gas appropriate?

This issue was agreed to in the Settlement Proposal.

e) Is the proposal for an updated harmonized Parkway Delivery Obligation (PDO) Framework, and the recovery of costs, appropriate?

In the OEB approved settlement proposal, parties agreed with Enbridge Gas's proposed updated PDO Framework subject to certain modifications. Parties also agreed to defer

Enbridge Gas's proposal to offer the Parkway Delivery Commitment Incentive (PDCI) payment to the former Enbridge Gas Distribution Central Delivery Area customers to Phase 3 of the proceeding.

f) Is the 2024 Test Year Parkway Delivery Commitment Incentive (PDCI) Forecast appropriate?

PDO Shift Recovery in Rates

As part of the merger proceeding, FRPO argued that an appropriate base rate adjustment would be additional costs of recovery emanating from costs of some Dawn Parkway assets utilized for the purpose of facilitating the PDO shift[24]. EGI (at the time, AMALCO)[25] argued against such an adjustment. The Board's decision found:

> *The OEB has determined that there is insufficient evidence to determine whether, as a result of the implementation of the PDO, ratepayers are paying twice for the same capacity. The OEB requires Amalco to track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing period. The OEB at the time of rebasing will review the costs and amounts recovered through rates to ensure that ratepayers are not paying twice for the required capacity and the legacy Union Gas is not enhancing earnings contrary to the intent of the PDO settlement agreement.*

While FRPO appreciates the Board's acknowledgement of our concern, we accept that we did not provide sufficient clarity in our submissions in the merger proceeding. Most importantly, to clarify, the additional or double recovery emanates from the nexus of the 2013 Rebasing decision and implementation of the PDO in the primary IRM term. It is the additional recovery through the PDO Shift of costs that were already in rates in 2013 that we submit ought to be removed from base rates at the end of 2018. Otherwise, without a formal rebasing in 2019, this over-recovery would continue into the second deferred rebasing period.

Our main points in support of removal of these additional costs are:

1) Costs for capacity surplus to the system demand needs were incorporated into 2013 base rates

[24] EB-2017-0306/0307 FRPO_IntrvARG_EGDI_Union Amalgamtn_20180615, pg. 6-16
[25] EGDI_UNION_ReplyARG_20180629, pg. 67-72

2) By implementing the PDO shift, UGL increased its recovery from Dawn-Parkway capacity by adding the costs of Temporarily Available Capacity and eventually Dawn-Kirkwall to its base rates which were already included in the rebased costs.
3) These additional costs remained in rates throughout the IRM term of 2014 to 2018 while rates escalated due to additional capacity builds effectively enhancing return while reducing risk.
4) FRPO accepts that ratepayers are responsible to pay these costs as parties to the Settlement Agreement for the Reduction of the Parkway Delivery Obligation until the end of 2018.
5) It would have been appropriate and equitable to remove these costs from the revenue requirement at the start of the second deferred rebasing period similar to other adjustments made at that time.

Given the contents of the preceding references, we will not repeat all of the evidence and submissions from the merger proceeding but will advance a simpler, more specific approach.

Background

The Dawn Parkway system has provided transmission of natural gas for Union Gas Limited (UGL) customers in Union South and North and Enbridge Gas Distribution (EGD) rate zone along with other ex-franchise customers for decades. Prior to the onset of the de-regulation of natural gas markets in 1985, UGL received deliveries from TransCanada Pipelines (TCPL) at Parkway (or Trafalgar as it was once called). By receiving gas from TCPL at the end of its system to which UGL delivered gas with the Dawn-Parkway facilities, the system could use these deliveries to reduce the facilities required to meet its obligations. As compensation for committing to these deliveries, parties providing gas to Parkway received compensation in the form of the Delivery Commitment Credit (DCC). This arrangement benefited all customers of the system by keeping rates lower. Although this arrangement of firm supply at the end of the pipeline was not called an Integrated Resource Planning (IRP) alternative, clearly it was and is just that today.

After deregulation opened the markets, large, sophisticated customers saw the economic opportunity of buying their own gas. Through OEB proceedings, notably EBO 412, the Board approved constructs to allow customers to make their own purchasing arrangements. One such approach was the temporary assignment of TCPL contracts by

UGL to customers. In receiving this assignment, direct purchase customers also took on the obligation to buy and deliver their gas at Parkway on a firm basis to continue the benefits of these deliveries. Many of these initial direct purchase customers were large industrials including those in the Sarnia area west of Dawn.

As the natural gas market continued to evolve and supply sources closer to the Union Gas franchise were available, the difference in cost to deliver gas at Dawn versus Parkway widened. In addition, UGL's application to remove the compensation to deliver firm gas at Parkway, the DCC, was approved by the Board in an earlier proceeding.[26] Large, sophisticated customers recognized the higher costs of Parkway deliveries and sought relief to move back to Dawn. In their view, Parkway-obligated delivery customers were paying while all other customers were benefiting. This is the historic inequity referred to in the Settlement Framework for the Reduction of Parkway Delivery Obligation (PDO).[27]

1) Costs for Capacity Utilized for PDO Shift were Already in Rates

It is undisputed that the costs associated with the Temporarily Available Capacity were recovered in rates as a result of the Board decision in the 2013 Cost of Service proceeding.[28] In spite of the demand being 210 TJ less than the capacity and associated costs, the Board approved full recovery of the costs spread over the lower demand. In the Decision, as referenced by EGI in their AIC [29], the Board relied upon UGL's reply argument:[30]

> *In reply, Union rejected CME's proposal to adjust the M12 Long-term Transportation revenues. Union reiterated that it had experienced significant turnback on the Dawn-Parkway and Dawn-Kirkwall systems and this has resulted in a lower forecast in 2013 as compared to 2011 and 2012.*

With that reliance, the Board found:

> *The Board rejects LPMA's request to establish a variance account related to Long-term Transportation Revenue, as the Board believes that Union should continue to bear this forecast risk, consistent with the current treatment.*

[26] RP-2002-0130 dec_w_reasons_union , para. 251-270
[27] EB-2013-0365, Appendix B, Page 1, para. A1
[28] Exhibit I.4.7.FRPO-169, Note (3)
[29] EGI AIC, pg, 208, para. 558
[30] EB-2011-0210 Dec_Order_Union 2012 CoS_20121025, pg. 21

Upon reviewing this aspect that EGI is promoting, FRPO would like to draw the Board's attention to an important matter. UGL's argument-in-chief was delivered August 13th and their reply argument was delivered September 5th both of 2012. In each argument for 2013 costs, UGL pointed to turnback of M12 capacity in 2011 and 2012. [31] [32] Upon consideration of these submissions in retrospect, we were perplexed as we recalled that UGL initiated their application to increase capacity on the Dawn-Parkway system in early 2013.[33] A review of that application reveals that UGL's Open Season and Reverse Open Season closed May 4, 2012 [34] more than 3 months prior to submitting the above arguments pointing to turnback risks. Further review of that application provides the results of those Open Seasons: [35]

> *Union held an open season and a reverse open season in 2012 which resulted in net incremental demands of 687,346 GJ/d.*

While these demands were not brought into evidence in the rebasing proceeding, in our respectful submission, UGL would have a positive obligation in disclosure that ought not allow this new information to be withheld from the Board in making submissions upon which the Board would rely.

Notwithstanding our concerns over the voracity of the information upon which the Board relied, FRPO accepts that the Board allowed EGI to put all of the Dawn-Parkway costs, including the 210 TJ, into rates spread across the lower demand on the system. In our view, this did not result in UGL bearing the forecast risk as the utility was granted the opportunity to put those costs into rates of a lower demand AND maintain the opportunity to sell that capacity.

2) PDO Shift Created Opportunity to Over-Recover Relative to Costs

In negotiations, and subsequently included in the Agreement, UGL Gas identified that there was additional Dawn-Parkway capacity deemed to be "Temporarily Available Capacity" that would be the initial step to allow a shift of some obligated Parkway deliveries to Dawn. UGL recognized that it was in a position to sell that capacity which would result in a temporary shortfall. UGL committed to managing the shortfall until

[31] EB-2011-0210 Transcript_Volume 13_Argument-in-Chief_20120813, pg. 26
[32] EB-2011-0210 Transcript_Volume 16_September 4 UNION REPLY_20120905, pg. 32
[33] EB-2013-0074 Union_APPL_LTC_20130402
[34] EB-2013-0074, Section 7, pg. 5
[35] EB-2013-0074, Section 1, pg. 1

Dawn to Kirkwall capacity that was expected to be turned back became available.[36] Also, because the Dawn-Kirkwall capacity was contracted at the time of rebasing, those costs were also in the 2013 base rates.[37]

This approach allowed UGL to recover all of the costs for the 6803 TJ of Dawn-Parkway capacity in rates PLUS an additional amount for the first 146 TJ of PDO shift implemented in the first year of the incentive period.[38] We would like to emphasize that we have not included the capacity from Customers with M12 service as, in the case of this capacity, PDO payments for that the 66 TJ[39] of capacity replaced cost recovery from those customers that would have been included in the first year of rebased rates.

3) Capacity Costs Remained in Rates While Rates Escalated in the IRM Term

During the IRM term, UGL eventually used Dawn-Kirkwall capacity to facilitate the PDO shift as contemplated by the Agreement. The eventual amount shifted was increased to 200TJ using the Dawn-Kirkwall capacity. [40] For each year of the IRM term, UGL increased the base rates for capacity in accordance with the Board approved ratemaking. In addition, UGL increased the Dawn-Parkway system capacity with facility builds in three successive years, 2015-2017, for which the cost of the builds was included in rates using the capital pass through. The higher marginal costs for capacity provided by these builds increased the M12 rate from $2.604/GJ in 2015[41] to $3.154/GJ in 2018.[42] In fact, if the PDO shift had not occurred, the scope of facilities required to meet demand would have been lower as unsold capacity could have been used to meet the increased demand. The increased capital requirements of these builds further increased the benefit of the PDO shift to UGL.

4) Ratepayer Are Responsible for these Costs for the Term of the Agreement

The Agreement facilitated some relief of the obligation to make Parkway deliveries for those who had faced the historic inequity. Further, it re-established an incentive (Parkway Delivery Commitment Incentive or “PDCI’) in recognition of continued firm, obligated deliveries for those who could not get full relief. [43] As a result, those

[36] EB-2013-0365, Appendix B, Page 4. para. B2 iii.
[37] Exhibit I.4.7.FRPO-169, line 1 a)
[38] Exhibit I.4.7.FRPO-169, line 1 b) plus line 8b)
[39] Exhibit I.4.7.FRPO-169, line 14 b)
[40] Exhibit I.4.7.FRPO-169, line 9 e)
[41] EB-2014-0271, Rate Order, Appendix A, pg. 14
[42] EB-2017-0087, Rate Order, Appendix A, pg. 14

[43] EB-2013-0365, Appendix B, Page 4, para. B2 (ii) 4.

customers seeking a more equitable approach have either had their obligations reduced and/or were compensated for their contribution to keeping the Dawn-Parkway system costs lower for the benefit of all shippers. As a result, we understand and respect that there is a need for ratepayers to pay for PDCI and costs associated with capacity used to create the shift for the term of the Settlement Framework which terminated December 31, 2018. [44] We are not disputing that as signatories to the Settlement Framework.

5) Base Rate Adjustments – Mechanism for Making Just and Reasonable Rates

The Settlement Framework was carefully written with context and guiding principles. The following sentence limited the term of the agreement and carried the guiding principle of equity for the parties.

> *The ultimate objective of the modified proposal is to remedy an inequity. The guiding principle is to keep Union whole rather than to enhance or reduce its earnings during the operation of the Incentive Regulation Mechanism ("IRM") to December 31, 2018.*

It was anticipated that costs would be rebased in 2019 and parties could take their respective positions in such a review. Absent that opportunity, due to the request by UGL and EGDI that the rebasing be deferred, the Board still needed to establish just and reasonable rates for the subsequent period. Recognizing this need, the utilities requested four base rate adjustments. Ratepayers requested and the Board accepted that further adjustments recommended by ratepayers would also be considered by the Board.

It is in this context that FRPO offered its original request for the base rate adjustment to eliminate what in our view was and has been a double recovery of capacity costs. We specifically requested the base rate adjustment for the start of the deferred rebasing period since there was no opportunity to rebase these costs. [45]

If there had been rebasing, in-franchise ratepayers would have had opportunity to argue that UGL had enhanced earnings during the primary rebasing period and that additional "responsibility" to keep Dawn-Parkway system smaller at a resulting lower cost should be removed, in part, as in-franchise, direct purchase obligation. This would be in recognition of the fact that all firm obligated deliveries made at Parkway were paid

[44] EB-2013-0365, Appendix B, Page 1, para. A3
[45] EB-2017-0306/0307 FRPO_IntrvARG_EGDI_Union Amalgamtn_20180615, pg. 15, para 5.20.

for by in-franchise customers even though these in-franchise customer needs represented less than 20% of demand served by the system.

An argument could be made that in-franchise customers have subsidized M12 rates for decades by paying the premium to deliver at Parkway to reduce facilities needed in the system thus keeping the cost of the system down for all customers and shippers who use the system. The extension of that argument is that the value of these deliveries benefits all customers and shippers and so the cost of the PDCI should be funded through M12 rates as opposed to the much smaller beneficiary pool of in-franchise customers.

While we recognize that we are dealing with the counter-factual, some relief would have been sought by parties including FRPO. In the alternative to the significant departure to the existing PDO construct, parties could have simply argued for the removal of the on-going payment for 200 TJ of surplus since ratepayers paid incremental revenue relative to the cost of service in paying for the PDO shift throughout the initial IRM period. Given that we cannot go back in time to a rebasing proceeding that did not happen, it is the simpler base rate adjustment as of January 1, 2019 that are pursuing .

6) UGL Over-earned through the PDO Shift Framework

As identified in section 1), UGL was not at any real risk for the unsold M12 capacity of 210 TJ due to their knowledge of requested demand from their recent Open Season. Yet, the Board granted the recovery of the costs of that capacity across the existing lower demand relying on UGL evidence and arguments . UGL's negotiation of an agreement to then use that capacity - eventually to be substituted for by Dawn-Kirkwall capacity – for PDO shift allowed for recovery above the costs associated with the existing capacity in place at the start of 2015. Further, in knowing the scale of new demand, allocating the Temporary Available capacity to the PDO shift increased the need for new facilities to meet the increasing demand. These new facilities created increased recoveries underpinned by long-term contracts. We cannot determine the incremental earnings of the required facilities, but we can state they increased earnings in the primary IRM period.

RELIEF SOUGHT

In spite of this, FRPO respectfully submits that ratepayers accepted the Settlement Framework and thus the cost consequences through the term of the agreement ending in 2018. But, in our view, in-franchise ratepayers should not be burdened with this on-going over-earning in the deferred rebasing period. While we cannot recreate what would have happened in a 2019 rebasing proceeding, we can request that the adjustment to remove the cost consequences of the 200 TJ of Temporary Available/Dawn-Kirkwall capacity be made as of January 1, 2019.

In trying to establish an evidentiary basis for the specific amount, FRPO tried to explore cost allocation associated with the evolution of the system during the initial IRM period.[46] We were trying to understand some factors to consider an equitable allocation of the costs of the 200 TJ amongst shippers and ratepayers as January 1, 2019. However, upon development of our argument and in recognition of the contribution of in-franchise ratepayers to lowering the M12 rates through the provision of PDO during the primary IRM term, FRPO respectfully submits that the cost of the 200TJ of capacity be removed from rates after 2018 and returned to in-franchise ratepayers according to the rate class contribution to M12 rates as of that date (in-franchise ratepayers pay for over 96% of the 2023 cost of PDO shift/PDCI)[47]. A simple proxy for the total amount would be estimated by taking the 200TJ[48] numerator divided by the denominator of 280 TJ[49] multiplied by the Dawn-Parkway Demand Costs of $9.726M[50] for an annual reduction of $6.95M for in-franchise ratepayers for the Deferred Rebasing period of 2019-2024.

19) With respect to the Gas Supply Plan,

a) Is the proposal for implementation of the 2024 Gas Supply Plan after the OEB's decision on matters relating to the 2024 Gas Supply Plan is issued, and for reflecting cost variances1 in gas cost deferral and variance accounts, with recovery being subject to prudence review, appropriate?

b) Is the proposal to extend the deadline for filing the next 5-Year Gas Supply Plan by an additional year appropriate?

Parties agree with Enbridge Gas's proposal for implementation of the 2024 Gas Supply Plan after the OEB's decision on relevant matters is issued, and for reflecting cost variances in gas cost deferral and variance accounts.
Parties further agree that it is appropriate for Enbridge Gas to defer the filing of its next five-year gas supply plan for one year.

[46] Final Transcript EB-2022-0200 Enbridge Gas Rebasing Vol 13, pg. 57-72
[47] EB-2022-0133, Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 11, pg. 1
[48] Exhibit I.4.7.FRPO-169, line 11 e)
[49] Exhibit I.4.7.FRPO-169, line 15 e)
[50] Exhibit I.4.7.FRPO-169, line 16 e)

D. Cost of Capital

20) Is the proposed 2024 Capital Structure, including return on equity, appropriate?

21) Is the proposed 2024 cost of debt and equity components of the capital structure appropriate?

22) Is the proposed phase-in of increases to equity thickness over the 2024 to 2028 term appropriate?

Once again, IGUA took the lead in engaging experts and testing the evidence. We support and adopt IGUA's submissions on behalf of ratepayers and to assist the Board.

E. Revenue Deficiency/Sufficiency

23) Is the proposed 2024 Test Year Revenue Deficiency calculated correctly?

Clearly, a decision is needed on significant material items in this Phase to allow calculation of revenue deficiency, if any, to be reviewed by staff with input from the parties to be determined by the Board.

F. Cost Allocation

24) Is the 2024 Cost Allocation Study including the methodologies and judgements used and the proposed application of that study to the current rate class design, appropriate?

Deferred to Phase 3.

G. Rate Design

25) Is the proposal to set 2024 rates using current rate classes and an updated harmonized cost allocation study appropriate?

26) Is the proposed rate design proposal for the gas supply commodity charge and gas supply transportation charges appropriate?

27) Is the proposed rate implementation and mitigation plan for 2024 rates appropriate?

The agreed to approach to interim Phase 1 rates was part of the Settlement proposal.

28) Are the proposed changes to the terms and conditions applicable on January 1, 2024, to existing rate classes appropriate?

Deferred to Phase 3.

29) Are the proposed miscellaneous service charges, including Rider G and Rider M, appropriate?

In addition to consideration of other matters, such as EBO 188, which must be considered toward rational economic expansion in light of Energy Transition, we support the implementation, on a temporary basis of the ELC, at a rate of $159/m for additional service length beyond 20m. In our view, this initial step would align with recognizing the additional cost that need not be subsidized, especially given the risk on the revenue horizon. We support a further review of this rate in conjunction with potential changes to the revenue horizon associated with EBO 188.

30) Are the proposed Direct Purchase Administration Charge (DPAC) and Distributor Consolidated Billing (DCB) charges appropriate?

Agreement in Settlement Proposal.

I. Deferral & Variance Accounts (Exhibit 9)

31) Is the proposal for harmonization of certain existing deferral and variance accounts appropriate?

32) Is the proposal to close and continue certain deferral and variance accounts and establish new ones appropriate?

33) Is the proposal to dispose of the forecast balances in certain deferral and variance accounts appropriate?

Several Deferral and Variance Account changes were included in the Settlement Proposal. In addition, many parties agreed to defer the resolution of other Accounts to Phase 2 and 3 of the proceeding. The Remaining accounts, supplemented by additional EGI requests after the Settlement Conference, are:

A) Volume Variance Account
B) Short-term Storage and Other Balancing Services Account (Union rate zones)
C) Panhandle Regional Expansion Project Variance Account

D) Tax Variance Deferral Account

E) Accounting Policy Changes Deferral Account

A) Volume Variance Account

With the voluminous information in this proceeding, some issues seem to fly under the radar. While EGI provided initial evidence on the Volume Variance Account , there is not a significant amount of evidence on how it would be implemented in a manner that respects the stated intent of de-risking in an equitable manner.

We understand that EGI views this proposed account as a precursor to the Straight Fixed Variable and Demand (SFVD) rate design for general service customers. However, the Board has not heard and determined that the SFVD is in the public interest and, of course, considered with other risk-alleviating mechanisms. Moreover, having seen the evolution of the LRAM/NAC and NAC as applied to storage in the UGL franchise in the past, we appreciate how volume variance is applied and to what accounts it applies have the potential to create unexpected or unintended consequences.

EGI provides evidence of the variability of normalized volumes for general service customers in the current rate zones from one year to the next in its Operating Revenue evidence. A review of the variability in actuals versus the two forecast numbers yields an understanding that even the current methodologies do not work precisely. In our respectful submission, a merging of these accounts should have careful study that the evidence in this proceeding does not afford.

Given that the Board has not opined on the risk-alleviation of such steps as SFVD and the care with which any merging of accounts should be undertaken, we submit that the Board should not approve this account in Phase 1. Respectfully, the Board could determine upon hearing and determining other Phase 1 matters, when it believes that a consideration of this approach would be appropriate.

B) Short-term Storage and Other Balancing Services Account (Union rate zones)

EGI's AIC states: Enbridge Gas inadvertently failed to include the need to continue with the Short-term Storage and Other Balancing Services Account for the Union rate zones.

FRPO supports the continuation of the account until latter phases of the proceeding until matters dealing with storage and potential rate harmonization are dealt with in Phases 2 and 3.

C) Panhandle Regional Expansion Project Variance Account (PREPVA)

FRPO does not support the approval of the PREPVA as proposed by EGI as it is driven by opportunism of the ratemaking construct. As described effectively in the SEC submissions, we do not support an account that would preclude access to the CCA benefit of the project to ratepayers. Further, if the Board deems it prudent to include the variance account in the event that the project is not approved, that would be a more equitable and foresighted determination in our view.

D) Tax Variance Deferral Account

As FRPO opposes the inclusion of the Integration Capital in the 2024 rate base, it stands to reason that if the shareholders are funding this capital, EGI should get the benefits of the accelerated CCA. If the Board determines that Integration Capital can be included in the rate base, then the balance should revert to ratepayers.

E) Accounting Policy Changes Deferral Account

FRPO benefited from the work of SEC and the Ontario Greenhouse Vegetable Growers (OGVG) in bringing this issue into clarity. As such, we support and adopt the submissions of SEC as their submissions outline the background and the reasoning including the work done by OGVG to demonstrate the inequity of EGI's request in this proceeding.

J. Other

34) Is the proposed regulatory treatment of the Natural Gas Vehicle Program appropriate?

Given the larger, more central issues in this proceeding, we believe consideration of the Program should be done at a time where the issue can be better explored. FRPO supports OEB staff recommendation to accept EGI's proposed regulatory treatment of the NGV program subject to the 2026 report that would set out evidence for a considered review of the program in light of other Energy Transition evolutions. From EGI's response to Board staff IRR's, it appears that EGI would consider filing the report. In our respectful submission, if the Board determines that approach is appropriate, it would be important that EGI be directed to file the report in 2026 to reduce the risk of additional and, perhaps, unnecessary deferral.

35) Is the proposed regulatory treatment of the Distributor Consolidated Billing Program appropriate?

Parties settled this issue in the Settlement Proposal.

36) Is the proposal for the extension of the existing financial terms of the Open Billing Access Program for ten months until October 31, 2024, appropriate?

Parties settled this issue in the Settlement Proposal.

37) Is it appropriate to have an earnings sharing mechanism for 2024?

Yes, FRPO believes that it is in the public interest to have an earnings sharing mechanism in 2024. EGI and its predecessor companies have a long history of over-earning relative to the Board approved rate of return.[51] This comfort with over-earning has resulted in EGI presenting its revenue sufficiency and deficiencies in the deferral disposition introductions as relative to the Board-approved ROE plus the deadband. This is a large and complex proceeding dealing with a 10-year gap since full rebasing and the merger of the two legacy utilities in the context of Energy Transition. EGI produced tens of thousands of pages of evidence including discovery responses while advancing dozens of proposals with hundreds of data forecasts. FRPO agrees that there was an opportunity to test the evidence and EGI has been generally responsive. However, the scope, scale and complexity one would think that having protection for both sides would be a prudent step.

It is telling though, that EGI is not interested in this protection for interests. Clearly, one would think that they are not going to be successful in getting approval for all its proposals. Yet the company seems confident that it does not need or want any downside protection that a symmetrical ESM could provide. This is from a company who is seeking increasing equity thickness in the first year to recognize increasing risk. Given that the ESM does not hurt the utilities risk, we believe that ESM is in the public interest in a time of significant change.

[51] Exhibit I.5.3-IGUA-30, Attachment 1

38) How should Dawn Parkway capacity turnback risk be dealt with?

The Dawn-Parkway system serves as the backbone of the transmission network of the Union South rate zone and an essential link for customers in north-east North America who want to access the benefit of the Dawn storage system which now includes the EGD Tecumseh (or Corunna) storage fields. At the time of the 2013 Union Gas rebasing, 84% of the demand on the system served ex-franchise customers due to its importance as a link to storage.

In 2013, the major expansions of the Dawn-Parkway and GTA systems were approved to accommodate a sourcing of deliveries of natural gas from the Appalachian region in northern US states of Pennsylvania and Ohio. These expansions were driven by the prospect of lower priced delivered gas. While these projects were still under construction, UGL applied for an additional expansion to the Dawn-Parkway system.[52] Most of the capacity of these expansions were contracted for ex-franchise customers. Concerned ratepayers collaborated to sponsor a study of the risks of the ex-franchise customers turning back capacity after the primary term of their contracts or other contracts being turned back leaving in-franchise customers bearing the capacity costs. The study was prepared by Mr. John Rosenkranz.[53]

Through the Settlement process in that proceeding, the parties reached no agreement on the how the turnback risk should be dealt with in the context of the proposed facilities. Parties agreed that this issue will be dealt with in UGL's next cost of service proceeding.[54] A pertinent excerpt from that the Settlement proposal states: [55]

> *For the purposes of settlement, while the parties agree that leave to construct should be granted, there is no agreement of how turnback risk should be dealt with in the context of the proposed facilities. Parties agree that this issue will be dealt with in Union's next cost of service proceeding. For greater certainty, intervenors are in no way restricted or precluded from making any argument before the Board in that proceeding that it is appropriate that certain cost allocation measures should be put in place to insulate ratepayers from the effect*

[52] EB-2014-0261
[53] EB-2014-0261 CME_FRPO_OGVG_intrv_EVD_20150109
[54] EB-2014-0261, Settlement Agreement, February 27, 2015.
[55] Ibid.

> *of unutilized and underutilized capacity on the Dawn Parkway system due to potential turnback risk.*

In 2015, UGL applied for additional increase in capacity. While ratepayers relied on the commitment to address the risks of capacity turnback with the Board, there was still concern about asset recovery costs in the event of turnback. This concern led to an exploration of alternatives such as obligated deliveries at Kirkwall.[56] The resulting Settlement proposal contained a provision requested to add the consideration of alternatives prior to the next Dawn-Parkway builds:[57]

> *A number of parties further believe that given the accelerating pace of change in the market, future expansion applications should include evidence reflecting consideration and evaluation, including through consultation with the market, open season or by way of RFP, as, when and if appropriate, of the risks and benefits of permanent or interim non-facility alternatives to facility investment. These parties further suggest that, to start with, the topic could be usefully included in the Board's next Energy Sector Forum (as contemplated in the Board's March 31, 2015 Letter to interested parties at the conclusion of the EB-2014-0289 Natural Gas Market Review).*

Since the time of the resulting expansion in 2017, the only application for expansion by EGI was 2020.[58] There was a significant stakeholder response, not only from the ratepayer and environmental groups, but also, concerned citizens.[59] The application was initially adjourned and eventually withdrawn.[60]

EGI's evidence in this proceeding, supported by an ICF report, seemed to suggest business as usual without directly addressing the ratepayer concerns regarding turnback.[61] While much has changed since the original study, we were concerned that the central issue of turnback risk was not addressed fully in this evidence. As a result,

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[56] EB-2015-0200 Exhibit I.FRPO.13
[57] EB-2015-0200 Dec_Order_Union_2017 Dawn-Parkway Expansion_20151222, Schedule B, pg.15
[58] EB-2019-0159 EGI_APPL_updates_v2_20200131
[59] EB-2019-0159 Over one hundred letters of comment were received by the Board https://www.rds.oeb.ca/CMWebDrawer/Record?q=CaseNumber=EB-2019-0159&sortBy=recRegisteredOn-&pageLength=400
[60] EB-2019-0159 EGI_Project Status Report_20201022_eSigned
[61] Exhibit 1, Tab 11, Schedule 1 plus Attachment

FRPO engaged Mr. Rosenkranz to review the current market and provide recommendations to mitigate in-franchise ratepayer risk.

FRPO filed a report by John Rosenkranz that examined the demand for Dawn Parkway System transportation services from the perspective of the New York and New England gas distribution companies that currently hold long-term contracts with EGI. Mr. Rosenkranz found that the near-term risk that ex-franchise customers from New York and New England will turn back a large amount of Dawn Parkway System capacity during the next IRM period is small, but that the potential for capacity turnback is likely to increase over time as more gas infrastructure alternatives become available, and as state and local initiatives to reduce natural gas use and encourage the use of non-pipeline alternatives expand.

No parties rebutted this conclusion.

Mr. Rosenkranz recommends two actions that EGI could take to (a) limit cost shifting from ex-franchise customers to in-franchise services if turnback occurs, and (b) reduce EGI customers' exposure to capacity turnback by making it less likely that the Dawn Parkway System will be overbuilt.

The first recommendation involves the EGI rate design. Rate design issues will be addressed in Phase 3 of this proceeding.

The second recommendation would allow customers holding long-term contracts for Dawn Parkway System transportation service to submit a buyout offer when EGI holds a reverse open season under the Storage and Transportation Access Rule. Parties questioned how this proposal would work, whether it would create a disincentive for customers to offer turnback without payment in reverse open seasons, and what the cost implications would be for other EGI customers.

In his report, Mr. Rosenkranz pointed out that this recommendation is similar to other targeted demand-side management measures in which customers are compensated for reducing gas use during periods of high demand and is consistent with the Integrated Resource Planning (IRP) Framework, which requires EGI to consider demand side IRP Alternatives to meet system needs. In response to interrogatories, Mr. Rosenkranz clarified that contract restructuring payments would only be made if a buy-out proposal is found to be beneficial under the Board's IRP Framework.[62] Existing customers would be protected.

Some of the concerns raised in response to this recommendation appear to stem from the linkage to the existing reserve open season process. EGI speculates that allowing buyout payments would cause all customers to hold out for a payment before offering capacity in a reverse open season and suggests that Mr. Rosenkranz agrees.[63] To be clear on this point, Mr. Rosenkranz agreed that this was a possibility, but the fact that a buyout offer will may not be accepted would still be a reason for a customer that no longer needs Dawn Parkway transportation service to turn back capacity without compensation.

Allowing customers to submit a buyout price on the reverse open season form would be a transparent and non-discriminatory method of initiating contract restructuring discussions between EGI and any customers that may be willing to relinquish existing capacity to reduce or avoid the need for a future infrastructure expansion. However, tying contract restructuring opportunities to the existing reverse open season process is a not necessary element of this recommendation. The main point of the recommendation is that contract restructuring, including a restructuring that involves a buyout payment, is a demand side IRP Alternative that EGI should consider before submitting a leave to construct application for a Dawn Parkway System expansion project.

While Mr. Rosenkranz answered questions on specific examples in his oral testimony, he emphasized that there were many factors that would contribute to the analysis beyond just the cost of build (e.g., overrun risk, stranded assets from Energy Transition, etc.). The conceptual framework is best summarized in his exchange with Commissioner Moran:

> *MR. MORAN: Thank you. And, again, as I understand your evidence, you are not suggesting that we establish all of the fine details of the process; you are recommending a process to develop an approach that would be consistent with the IRP principles. Did I understand your evidence correctly on that?*
>
> *MR. ROSENKRANZ: Exactly. I mean, my fundamental recommendation is that Enbridge Gas be expected to investigate this alternative*

[62] Exhibit N.M4.SEC-1.
[63] Argument in Chief of Enbridge Gas at paragraph 795.

and identify if this alternative exists. Once it exists, then there is a process that has gone through a great deal of discussion and is being fine-tuned in terms of how build alternatives, versus non-build alternatives, would be evaluated.

FRPO submits that with the overlay of expected transition, EGI should directed to undertake this investigation including an assessment of the stranded asset risk on a probabilistic basis. This assessment would align with the Scenario modeling that Dr. Hopkins[64] and others supported in evaluating business risk. This approach would extend to the business risk of high capital, long-term assets such as Dawn-Parkway infrastructure. In our respectful submission, this approach would better balance ratepayer risks with shareholder opportunity than the historic approach of E.B.O. 134.

39) Is the proposed harmonized methodology for determining the amount of storage space and deliverability required to serve in-franchise customers appropriate, and is the proposed allocation of storage space and deliverability among customers appropriate?

These matters will be reviewed in Phase 2.

40) Should the OEB grant Enbridge Gas's request for a partial exemption for 2024 from the Call Answering Service Level, Time to Reschedule a Missed Appointment and Meter Reading Performance Measurement targets set out in GDAR?

No. FRPO was surprised and disappointed by EGI's response to Service Quality issues that have arisen since amalgamation. EGI committed to generate savings without impacting reliability and service quality and the Board relied on that when approving the merger.[65]

As FRPO attempted to bring these issues to the Board's attention as early as the end of 2021 through the IR process but EGI refused to answer nor acknowledge the issue including our preamble:[66]

We understand that UFG matters are out of scope. However, one of the integration activities that EGI has undertaken in the rebasing period is harmonization of meter readings cycles and integration of the billing systems. We have come to understand that the "notable change" is causing substantial

[64] Exhibit M8, pg. 5, lines 11-17 as a specific example
[65] EB-2017-0306/0307 Decision and Order, August 30, 2018, pg. 13
[66] FRPO_IR_EGI 2022 RATES P2_20211217, FRPO.22 - .28

> *customer billing issues which can transfer costs to the customer as some meters, especially in LUG, are not being read for months. We, and we trust the Board, want to understand the scope of the current challenge and what EGI is doing to correct the issues.*

These billing issues continued in 2022 and created customer cost for our members that cannot be quantified and will never be recovered. FRPO advised its members to contact the Board directly to address significant issues for which they could not get a response or, sometimes even someone at Enbridge to take their call in a reasonable amount of time.

FRPO renewed its pursuit of the issue in the regulatory process in the Deferral disposition proceeding later that year resulting in reporting commitments in the Settlement Proposal .[67] However, unbeknownst to us, the Board had engaged EGI with their concerns regarding these issues culminating in an Assurance of Voluntary Compliance ("AVC"). [68] While interim reporting appears to show some improvement, we find it almost insulting that EGI would now simply request that the Board lower the performance standard at the same time it is asking for "unrecovered integration capital" that created these systems.

Using the Meter Reading Performance Measurement (MRPM) as the prime example of what EGI is seeking (in our view, if they deliver the bills, their call volume would be reduced improving their Call Answer Service Level), EGI lays out its support for this request with five points:
1) Covid-19
2) Extreme weather events in 2020 and 2021 – noticeably not 2022
3)Loss of Key Meter Reading Vendor in 2019
4) "Double counting" some meters due to the length of disruption
5) Customers inhibiting access

FRPO respects that some of the first three factors likely contributed to the problem but should be, to some extent, in the past. The fourth point only exemplifies the scale of the problem. The fifth point is something a customer-focused utility should be able to overcome through customer relations or technology.

[67] EB-2022-0110
[68] EB-2022-0188 Assurance of Voluntary Compliance

Interestingly enough, EGI does not mention that the cut-over of their integrated billing system occurred in July of 2021. From the FRPO member experience, it is this time period where billing issues skyrocketed. Through our interrogatories, we tried to elicit evidence to demonstrate this issue by asking about the number of estimated reads between the first and second half of 2021, but EGI could not provide the data for the UGL rate zones for the first half. However, the percentage of estimated meter reads for the second half of 2021 were more than 20% higher than the percentage of estimates in the EGD rate zone for the same period.[69] More telling was EGI's response to our questions regarding wait time and call abandonment in 2021. The average wait time increase by almost a factor of 4 and the call abandonment rate increase from 8.6% to 22.7%.[70] Yet, amongst the factors that EGI identifies, there is no mention of the integration of the billing system.

In our respectful submission, the SQR levels should not be adjusted until EGI has demonstrated proactive approaches to improving customer service with reporting on initiatives and results that can be tested. The evidence of these efforts may demonstrate that customer service still matters to the integrated utility.

K. Rate Implementation

41) How should the OEB implement the approved 2024 rates relevant to this proceeding if they cannot be implemented on or before January 1, 2024?

FRPO respects the amount of effort required of all parties in the proceeding given the scope, scale and complexity and, therefore, does not object to EGI recover the annual review requirement deficiency or sufficiency for 2024.

ALL OF WHICH IS RESPECTFULLY SUBMITTED ON BEHALF OF FRPO,

Dwayne R. Quinn

Digitally signed by R. Dwayne Quinn
DN: cn=R. Dwayne Quinn, o=DR QUINN & ASSOCIATES LTD., ou=PRINCIPAL, email=drquinn@rogers.com, c=CA
Date: 2023.09.19 17:21:19 -04'00'

Dwayne R. Quinn
Principal
DR QUINN & ASSOCIATES LTD.

[69] EB-2022-0110 Exhibit I.FRPO.22
[70] EB-2022-0110 Exhibit I.FRPO.27