ONTARIO ENERGY BOARD

EB-2012-0459

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing rates for the sale, distribution, transmission and storage of gas commencing January 1, 2014.

Final Argument of the Federation of Rental-housing Providers of Ontario

April 22, 2014

1. INTRODUCTION

Enbridge Gas Distribution Inc. ("EGD") filed an Application to the Ontario Energy Board (the "Board") on July 3, 2013 for the establishment of distribution rates for the period of 2014 to 2018. A tremendous amount of time has been invested in the preparation, discovery and testing of the evidence resulting in thousands of pages of record. However, given the billions of dollars requested and the unorthodox approach by the company, the quantity of time and evidence is understandable.

This the Final Argument of the Federation of Rental-housing Providers of Ontario ("FRPO").

At the outset, we would like to thank the School Energy Coalition ("SEC") for its outlining of its positions well before the end of the oral hearing and substantial drafting of its argument very soon after the close of the oral hearing. As a result of their investment of time, we were able to know our ability to adopt large portions of their positions and focus our investment on time on areas where we could assist SEC, other intervenors and, most importantly the Board with targeted areas of the Application. We also appreciate the circulation of drafts by other intervenors and the early submission of Board staff . A read of these submissions affirmed our approach on focusing on areas that were not covered by others with the comfort of knowing the Board is well assisted in all areas.

2. THE ENBRIDGE FORECAST PROPOSAL

EGD has submitted an application for a customized Incentive Regulation ("IR") approach to rate setting for the five year period of 2014 to 2018. At the outset of the proceeding, FRPO expressed concerns[1] about the nature of the application in support of more comprehensive submissions by SEC[2]. In our view, the proposal did not provide the appropriate balance of incentives and risks

[1] FRPO Letter to the Board dated August 2, 2013
[2] SEC Letter to the Board dated July 20, 2013

between shareholders and ratepayers. It also did not fit the model of recent IR frameworks for natural gas utilities. Given the Board's decision to proceed without a preliminary issue, we were greatly assisted by Board Staff's submission of the Pacific Economics Group Research Assessment and Recommendations[3].

Through the course of the discovery process and oral hearing, our knowledge of and concerns with EGD's application grew. In reviewing the initial draft of argument provided by SEC, we respected their approach to addressing the policy issues and practical challenges facing the Board and ultimately ratepayers. Through feedback and dialogue with SEC, we determined our best investment of time on this issue was a focus on the core capital requirements and specifically those tied to system integrity and reliability management. After previewing one of the last draft of SEC's submissions, we support their submissions on The Enbridge Forecast Proposal in their entirety and find their argument compelling in the context of Methods of Setting Just and Reasonable Rates. Accordingly, we adopt SEC's recommendations on rate setting through the Empirical Method.

2.1. Capital Requirements

Our understanding of one of the prime drivers EGD asserted for its Customized IR approach was the increase in capital costs and its variability lumpiness through the IR term. Our understanding of EGD' s position on this was confirmed in oral examination[4]. In further examination, we drew the witness panel's attention to the graphical presentation of their budgeted capital spend in the upcoming incentive period versus the past period[5]. With the GTA and Ottawa projects removed due to their Y factor treatment, the EGD witness panel agreed with our proposition that the variability of resulting capital expenditures was similar in the last IR period and the upcoming period with one caveat[6]. That caveat was EGD had already performed some smoothing through the removal of variable costs. In our view, this prior smoothing performed by EGD is only further evidence of the discretion in these expenditures.

[3] Exhibit L, Tab 1, Schedule 2
[4] Transcript Day 5 Oral Hearing page 10, line 9 to page 11, line 7
[5] Exhibit TCU2.15
[6] Transcript Day 5 Oral Hearing page 17, line 2 to page 18, line 3

In addition, we attempted to understand the rigour that EGD asserted to bring into its cost estimates[7]. In our view, any project that is replicated year over year improves as a result of the initial learning curve and application of what worked well and what did not work well in the previous year. Using the list of individual projects, we invited EGD staff to provide us a list of projects to which that type of engineering estimating was applied. The resulting undertaking response did not provide any projects to which this type of improvement was applied[8]. Instead, we were pointed to high level undertakings that reiterated evidence of cost containment in the face of cost pressures and to the two IR's that detail the projects and the budgetary evolution. A simple scan of the project budget figures verifies that there was no application or expectation of performance improvement on a systematic basis. While we understand EGD can vary the scope or pace of projects, in our view, any reduced costs as a result of improvements in planning and execution of the projects were not included in EGD's budgetary rigour. Instead the practical effect be that these improvements would be become profit opportunity.

Lastly in this area, we asked about the budgetary impact of the projects that were driven by the asserted Fundamental Technical Regulatory Shift[9]. While we did receive an undertaking response[10], given a complete review of the record after receiving the undertaking responses, we would respectfully submit that the Board put little weight on the numbers in that undertaking response as outlined in our next section of submissions.

2.1.1. System Integrity and Reliability Management Capital

System integrity and reliability, in the context of these submissions, refers to the practices and processes that contain natural gas within the closed pipeline system and ensure safe and reliable distribution services to end use customers. This use of terms is differentiated from upstream contracting and processes that ensure sufficient gas is available to the distribution systems from upstream pipeline sources during all non-force majeure conditions. System integrity and reliability has long been a hallmark of natural gas utilities. However, in the last couple of decades with

[7] Transcript Day 5 Oral Hearing page 20-27
[8] Exhibit J5.2
[9] Transcript Day 5 Oral Hearing page 28, line 22 to page 29, line15
[10] Exhibit J5.3

increasing data capabilities and root cause incident assessment, risk based modelling and management techniques have become increasingly prevalent amongst utilities and their safety regulators[11].

2.1.2. EGD Position - Fundamental Technical Regulatory Shift

In its opening statement of the EGD witness panel speaking to the reasons behind the significant increase in capital budget requirements, the following statement was provided:

> *"The first is a fundamental technical regulatory shift that requires the company to assess both potential failures for all operating assets, and to proactively mitigate before these failures occur."*

EGD's position that it was new that the company ought to assess potential failures and proactively mitigate before the failures occur was quite surprising. Based upon our knowledge of the evolution of risk-based analysis in the TSSA's safety regulations, we inquired regarding EGD's perspective on this being a new requirement[12].

MR. QUINN: So it is specifically the integrity program as applied to pipelines operating less than 30 percent as specified minimum yield strength?

MR. SANDERS: That's correct. And I might add too, Mr. Quinn, I would also consider the -- going deeper into it and looking at the code requirements in Z-662, the language it talks about specifically identifying risk and failures before they occur, I see that as one of our fundamental shifts going into this next IR term.

Our obligation is to identify those risks and hazards and mitigate them before the failure occurs. I see that as a fairly fundamental shift.

[11] Technical Standards and Safety Authority, A Safer Ontario: The State of Public Safety Report 2004, page 4. Ref: http://www.tssa.org/corplibrary/ArticleFile.asp?Instance=136&ID=D1C2298D5D884D4BA2F05381F550D168
[12] Transcript Day 5 Oral Hearing page 11, line 27 to page 12, line 10

As the subsequent transcript demonstrates, the initiation of analysis of distribution assets for integrity management planning was first introduced in 2006[13]. EGD agreed to provide the results initial Distribution System Integrity Management Program[14] ("DSMIP"). A review of the contents of that initial DSMIP dated July 2009 provides the following in the Introduction[15]:

> *As outlined in the company's Integrity Management Program Manual, data will be collected, integrated and analyzed to establish the cause and frequency of failure and damage incidents in the distribution system. This information is to be used for the purposes of* ***identifying potential threats and risks to the distribution system and to establish grounds for possible mitigation of these threats****. The timeline for the data in this report is from 1 Jan 2008 to 31 Dec 2008 inclusive. (***emphasis added).**

While recognizing that this document was a work in progress, we view this excerpt as a prudent approach to the changing regulatory requirements. Using the data to identify potential threats and risks is clearly about assessing potential risks based upon accumulated knowledge. Establishing grounds for possible mitigation of these threats speaks to identifying risk reduction approaches and corrective actions. This identification and mitigation steps speak to EGD's accepting this coming change, in spite of the condition that the operating company "shall consider Appendix 1, Guidelines for Gas Distribution System Integrity Management Programs. Appendix 1 sets out items that "should" be included or considered in the DSIMP"[16].

However, EGD maintains its position that the Fundamental Technical Regulatory Shift is "from non-mandatory language to the current mandatory "shall" requirements of Clause 3.2"[17]. Later in that same undertaking, EGD states[18]:

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[13] Transcript Day 5 Oral Hearing page 12, line 11 to page 13, line 11
[14] Transcript Day 5 Oral Hearing page 14, lines 3 -13
[15] Exhibit J5.1, page 3
[16] Exhibit J5.11, bottom of page 2, top of page 3
[17] Exhibit J5.11, page 2
[18] Exhibit J5.1, page 4 and 5 (emphasis added by EGD)

The current 2012 TSSA CAD Amendment FS-196-12, adopts the CSA Z662-11, and now amends a clause in Chapter 12 by adding the following clause:

12.10.16

Operating companies shall establish effective procedures for managing the integrity of pipeline systems with an MOP less than 30% of SMYS (Distribution Systems) so that they are suitable for continuous service, in accordance with the applicable requirements of clause 3.2 of CSA Z662-11.

......

3.2 Pipeline system integrity management program

Operating companies shall develop and implement an integrity management program that includes effective procedures (see Clauses 10.3 and 10.5) for managing the integrity of the pipeline system so that it is suitable for continued service, including procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such condition and to manage integrity data. ***Such integrity management programs shall include a description of operating company commitment and responsibilities, quantifiable objectives, and methods for***

(a) assessing current potential risks;

(b) identifying risk reduction approaches and corrective actions;

(c) *implementing the integrity management program;* ***and***

(d) monitoring results*.*

2.1.3. EGD Awareness of Code Evolution - 2008

Codes and regulations provide minimum standards and guidance for professionals. So as not to go through a line by line assessment of the respective code language changes and EGD respective integrity management programs, we would submit that a review of key language in Code changes and EGD evidence provides sufficient evidence of evolution. While EGD and other utilities were developing their initial DSIMP's, another CSA Z662 code evolution was being adopted by the TSSA. EGD provides evidence of TSSA FS-121-08 noting that there was language substitution under Chapter 12 and only minor wording adjustments from the previous FS-087-06[19]. However, what was not provided was the language that was substituted.

TSSA FS-121-08[20] adopted the new CSA Z662-07 Code in January of 2008. Clause 12.10.13.1 of the code that was pertinent to Distribution Integrity Management was altered to be aligned with FS-087-06 but added the discretionary authority of the Director to require additional assurances of the utility for safety concerns[21]. While appreciative of the EGD provision of documents pertaining to the summary of safety regulation chronology, we were concerned that the replaced language of Code was not provided. Clause 12.10.13.1 of the CSA 662-07 that was substituted in the TSSA adoption reads as follows[22]:

> ***12.10.13.1***
>
> *Operating companies shall develop and implement an integrity management program that includes effective procedures (see Clause 10.3) for managing the integrity of distribution systems so that they are suitable for continued service, including procedures to monitor for conditions that may lead to failures, to eliminate or mitigate such conditions, and to manage integrity data.*
>
> ***Notes:***
>
> ***(1)*** *Guidelines for gas distribution integrity management programs are contained in Annex M.*
>
> ***(2)*** *Such management programs may include a description of operating company commitment and responsibilities, objectives, and methods for*
>
> *(a) assessing current and potential risks;*

[19] Exhibit J5.11, page 3
[20] Exhibit J5.11, Attachment 2
[21] Exhibit J5.11, Attachment 2, pages 4 and 5, article (14)
[22] CSA Z662-07 Oil and Gas Pipeline Systems, June 2007, page 281

(b) identifying risk reduction approaches and corrective actions;

(c) implementing the integrity management program; and

(d) monitoring results.

A comparison with Clause 3.2 of CSA Z662-11 excerpted above from the EGD Undertaking J5.11 reveals that the two are almost identical. It is clear the most important difference is the imperative "shall" in detailing components of the management programs in Clause 3.2 and the word "may" in the substituted clause 12.10.13.1. While noting there is a clear distinction, our submission is that EGD was very well aware of direction of the new Canadian Code in this area. With representation on many committees of CSA code development at that time, including the Subcommittees on Distribution and on Operations and Systems Integrity[23], EGD was very well informed on this evolution of Canadian standards. Further, given EGD admission of its involvement between 2008 and 2012 in the "shift in thinking from a failure based to a risk based approach to integrity management"[24], it is intuitively obvious that EGD was well aware of this regulatory change prior to 2012 and were in preparation for the inevitable change.

EGD may well argue that, given the above summary, they were aware of the evolution but that does not mean that they were acting in preparation for the need to assess current potential risks, identify risk reduction approaches and monitor the results. While we would argue that would not be a prudent approach, we believe that the argument is not necessary as EGD is on the record as taking proactive steps in this area of risk mitigation.

[23] CSA Z662-07 Oil and Gas Pipeline Systems, June 2007, pages xxi to xl
[24] Exhibit J5.11, Attachment 2, page 3

2.1.4. EGD Asset Plan 2012

As we do not have updates of the EGD DSIMP after the initial July 2009 report referenced earlier, we must look to the Asset Plan as the resulting document of the DSIMP and EGD's knowledge of risk mitigation. In the Asset Plan published May 9, 2012 , under the subsection System Integrity and Reliability, EGD documents[25]:

> *In terms of System Integrity, EGD must meet its regulatory obligation to comply with the CSA Z662 Oil and Gas Pipeline Systems standard. EGD will be required to comply with Annex N of the 2011 edition of this standard, Integrity Management Programs and Activities, when the Technical Standards and Safety Authority (TSSA) adopts the standard, likely later this year. At this time, EGD is required to comply with a form of Annex N that is included in the current standard.*

This paragraph is a clear indication of EGD's knowledge of continued evolution in the regulatory requirements in the area of risk mitigation. However, that is not to say that this prior knowledge has not been included in its practices as is articulated later in this same subsection[26]:

> *Learning from these experiences and consistent with an Asset Management System approach, EGD has been working to adopt a broader risk based decision making approach to Integrity Management. This is not only consistent with a best practice industry trend, it is consistent with the evolution of regulations from a traditional "prescriptive" approach to a "goal oriented" or "risk based" approach. Annex N of CSA Z662 is an example of regulation that is evolving in this direction.*
>
> *A risk based approach can be defined as a comprehensive and defensible process to identify threats, assess the potential risks from those threats, prioritize these risks and specify appropriate asset investments to mitigate likelihoods and impacts to effectively manage the risks.*

[25] EB-2012-0354, Exhibit B2, Tab 2, Schedule 1, page 39
[26] EB-2012-0354, Exhibit B2, Tab 2, Schedule 1, page 41

It is important to note that this excerpt speaks to Annex N. As clarified by EGD in its Regulatory Overview[27]:

> *A note following Clause 3.2 points to Annex N of the CSA Z662-11 for all pipelines. The CSA Z662-07 Annex M is not part of the new standard. This is the first time that the integrity management program required in respect of pipelines and systems operating at a MOP above and below 30% of SMYS were directed to the same code, clause and Annex. Prior to this, each was referred to separate codes or appendices which were not identical.*

Logically, putting the above clarification with EGD's Asset Plan statement, it is clear that they have working "risk based decision making approach to Integrity Management" that is aligned with approaches of the standard that will come into force later that year. The second paragraph of the Asset Plan quote speaks to EGD proactively identifying risks (anticipating) and taking steps to mitigate the likelihood and impact of the risk (mitigating).

But the question may be asked: how long has EGD been analyzing its risks proactively to provide mitigation? In our view, the next page of the Asset Plan contains the answer[28]:

> *EGD has also been striving to improve the condition monitoring of its assets to better understand the factors that contribute to failure rates. For the past five years, since Distribution System Integrity Management Programs have been mandated through the CSA standard and the TSSA, EGD has been working to comprehensively and proactively analyze asset condition and assess which threats contribute to higher failure rates.*

2.1.5. Conclusion

Enbridge has testified that the proactive identification of risks and subsequent mitigation is a recent "Fundamental Technical Regulatory Shift" and is now arguing[29]:

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[27] Exhibit J5.11, Attachment 2, page 4
[28] EB-2012-0354, Exhibit B2, Tab 2, Schedule 1, page 42

> *In short, the fundamental shift involves moving from a reactive approach of responding to failures when they occur to a proactive approach of anticipating failures and mitigating them before they occur.*

Code interpretation is always contextual. While authors of code and even safety regulators provide minimum standards, most also articulate that the standards must be applied with experience and judgment. The following clause has been replicated in many editions of the CSA Z662 and its predecessor codes[30]

> *This Standard is intended to establish essential requirements and minimum standards for the design, construction, operation, and maintenance of oil and gas industry pipeline systems. This Standard is not a design handbook, and competent engineering judgment should be employed with its use.*

It is our respectful submission that EGD's position that this Fundamental Technical Regulatory Shift occurred with the adoption of mandatory language in late 2012 is inconsistent with the evidence provided above and its own evidence from the rebasing case through its Asset Plan. To continue to assert that this recent shift justifies excessive increases in capital requirements would demonstrate a lack of engineering regard for sound judgment in the application of standards and knowledge of an evolution to which they contributed. Based upon the foregoing, we submit that EGD's premise of a Fundamental Technical Regulatory Shift causing substantial core capital increases ought to be rejected by this Board.

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[29] EGD Argument-in-Chief submitted March 31, 2014, page 30
[30] CSA Z662-07 Clause 1.4, page 2

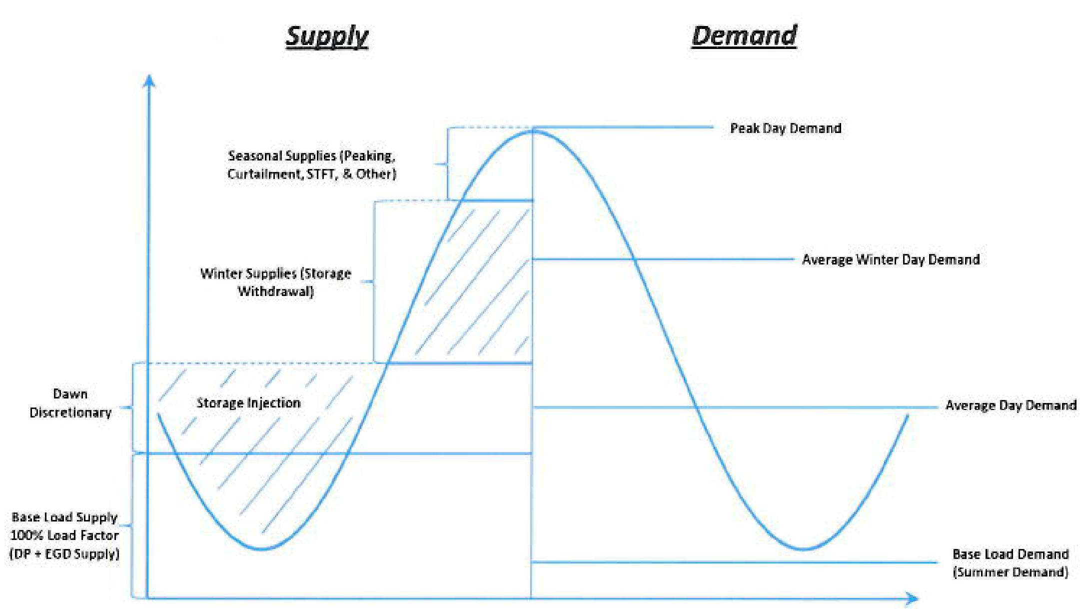
3. GAS SUPPLY

3.1. BACKGROUND

3.1.1. EGD Gas Supply Approach

For natural gas utilities in northern part of North America, system planners manage supply conditions around two key concepts: i) Meeting the gas consumption demands of its customers on the coldest design day of the winter (i.e., market demand on a peak day) and ii) ensuring that enough gas is purchased to meet seasonal demands throughout the year. EGD needs to manage its natural gas supply and demand to meet seasonal consumptions requirements that vary considerably between summer and winter. The utility uses a combination of annual firm contracting, storage injection and withdrawals, winter firm and peak deliveries and spot purchases to effect the seasonal balance. In recent proceedings, EGD has presented the following depiction of their approach.

Figure 3.1.1 Relationship of EGD Gas Supply and Demand[31]



[31] EB-2013-0046 Exhibit C, Tab 1, Schedule 6, page 2

The base supply portion is depicted as Base Load Supply 100% Load Factor. Historically, most of the Base Load Supply has been delivered by annual Firm Transportation ("FT") contracts with TransCanada Pipelines ("TCPL"). To maximize the economic value of annual contracting, EGD has stated in recent proceedings that it strives to maintain 100% Load Factor (i.e., the contract capacity is filled the entire year). This capacity serves in-franchise market requirements throughout the year. In the summer when this Base Load Supply exceeds market demands, the incremental gas is injected into storage for subsequent withdrawal in during periods of higher demand..

To meet increased market requirements of winter, EGD supplements its Base Load Supply with Storage Withdrawal and other deliveries such as Short-term Firm Transport ("STFT") with TCPL, Peaking Service or other deliveries. By increasing deliveries of gas during the higher consumption periods, the annual total of the daily Base Load Supply was maintained at a level less than the annual total of demand thus keeping the pipe capacity contracted annually fully utilized the entire year.

3.1.2. System Reliability

For natural gas utilities, meeting peak design day requirements is a cornerstone of system and gas supply design. A principle of design philosophy is that the utility can provide all firm customers adequate supply through well designed systems with gas supply that is reliable during peak conditions. While not emphasized on the EGD gas supply depiction, historically, other deliveries included a considerable portion of Interruptible Transport ("IT") deliveries from TCPL for both the company and the direct purchase market. In recent years, EGD had expressed concern with the risks associated with relying on IT services to meet its firm delivery obligations in the franchise. The resulting EB-2010-0231 proceeding approved an agreement for both EGD and direct purchase providers to increase the proportion of firm deliveries to the franchise[32]. These deliveries were facilitated by a considerable increase in STFT contracting by EGD to keep the annual quantities of

[32] EB-2010-0231 Decision dated ???

gas delivered by FT below the annual demand of the utility. As annualized contracting of FT on TCPL had fallen in recent years, STFT was readily available. Given bid floors established for this service, the unit costs of winter delivery with this service were very comparable to the unit cost of FT without the commitment of additional summer deliveries.

3.1.3. Peak Day Design

A key criteria in the determination of peak day market requirements is the establishment of "how cold is a peak day". The gas industry consensus approach is measuring the variance of the hourly temperature from a standard temperature for which it is presumed that there would be little to on gas consumption. Using 18 degrees Celsius as the standard for Ontario gas utilities, the average variance of temperature is stated as numerically as the Heating Degree Days ("HDD").

As described in its evidence in the rebasing proceeding[33], EGD sought an increase to the standard for its Peak Day for each of its respective regions. As a result of the Board's approval of the Settlement Agreement[34] in that proceeding, EGD phased in a two step increase in the HDD values for its design day. The higher HHD standard (i.e., colder expected temperature) served to increase the forecasted market requirements, thus increasing the required supply to meet the demand. Striving to secure firm deliveries to meet the peak and given the seasonal requirement for this delivery, EGD increased its reliance on STFT[35].

3.1.4. 2013 National Energy Board ("NEB") Decision

As a result of the most comprehensive NEB proceeding in over a decade reviewing TCPL rates, the NEB established FT transport rates at a level below TCPL's cost of service but provided TCPL full

[33] EB-2011-0354 Exhibit D1, Tab 2, Schedule 3
[34] EB-2011-0354 Decision dated
[35] Exhibit D1, Tab 2, Schedule 1, page 5-6

price discretion to meet its revenue requirement and incremental incentives[36]. The decision lowered the cost of the annualized firm transport contract while providing TCPL with unlimited price flexibility on discretionary services (non-annual). As outlined in EGD evidence[37], during the summer of 2013, the total cost of a 5 month STFT contract increased beyond the total cost of a 12 month contract.

3.2. <u>EGD/Intervenor Collaboration on Shift to FT</u>

On July 12, 2013, by way of letter, EGD informed the Board and intervenors of its intent to pursue FT transport instead of STFT citing the higher STFT tolls. Through an exchange of letters, in the next couple of months, FRPO requested the provision of the supporting analysis underpinning EGD's approach[38]. Through provision of the analysis[39] and the October 2, 2013 meeting, we, as FRPO, came to understand the challenge and accepted that the FT approach was the lowest cost. This evaluation included the recognition of the fact that in moving from winter only daily deliveries to annual daily deliveries, EGD would receive more gas in the summer than the cumulative total of its summer market demands and required storage fill. Said differently, if all of the incremental annual contract deliveries were received, EGD would exceed its maximum available storage capacity. Therefore, absent any other changes to gas management, some of the pipe capacity would need to be left empty resulting in an expectation of unutilized demand charges ("UDC").

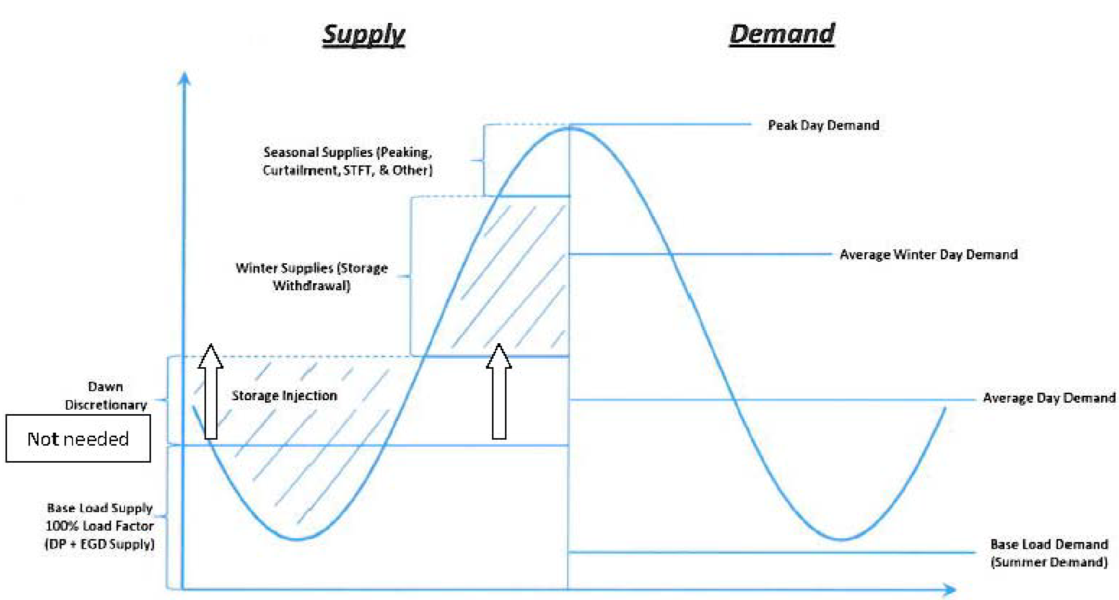
It is important to note that while the UDC would be forecasted, there are gas management strategies available to EGD to mitigate this risk. In assessing the situation, it was clear that EGD maintained approximately 18 PJ of Dawn Discretionary supply which could be eliminated from the plan thus allowing some of the additional FT contract capacity to be used during the summer. Historically,

[36] RH-003-2011 Decision dated ???
[37] Exhibit D1, Tab 2, Schedule 1, pages 11 and 12
[38] FRPO Letter to Board Secretary in EB-2012-0295 submitted September 16, 2013
[39] Exhibit N1, Tab 2, Schedule 1, pages 17-19

the Dawn Discretionary supply was not called on until EGD was assured that the summer contracts were fully utilized thus allowing EGD the opportunity to avoid un-forecasted UDC[40].

The result of this change in gas supply approach can be understood graphically by viewing a modified version of Figure 3.1.1 above and imagining that the horizontal line that signifies the level of Base Load Supply moves up more than the amount deemed Dawn discretionary thus eliminating the need for that component of supply. This shift would result in the new line exceeding Average Day Demand predicting the potential for leaving some Base Load Supply pipeline capacity empty so that the annualized needs of the utility come back into balance (see Figure 3.2 below). It is our view that the amount of capacity that is not needed nor wanted due to storage space limitations can be projected and released to the market to re-capture some of the cost of the capacity[41]. This ability to use FT capacity instead of purchasing Dawn Discretionary and the opportunity to release the transport is EGD's opportunity to mitigate UDC risk. This expectation of mitigation and our desire to monitor this process drove the reporting captured in Issue 1 of the Settlement Agreement[42].

Figure 3.2 Revised Relationship of EGD Gas Supply and Demand with Incremental FT



[40] Transcript Day 8 Oral Hearing page 30, line 17 to page 32, line 17
[41] Transcript Day 8 Oral Hearing page 32, line 18 to page 36, line 20
[42] Exhibit N1 Tab 2, Schedule 1, pages 6 and 7. Settlement Agreement, Aspects of Enbridge Gas Distribution 2014 Gas Supply Plan dated October 29, 2013

3.2.1. Benefits of Using Contracted FT versus Dawn Discretionary

By not buying Dawn Discretionary and filling the potentially unutilized capacity ratepayers benefit since contracted FT is, in our view, a sunk cost. We hold this view because if the capacity is filled, the only marginal costs are fuel gas and the variable commodity rate. Then the total cost would be recovered through the transportation rate. If the pipe capacity is left empty and the gas is purchased as Dawn Discretionary the ratepayers pay for the implicit transportation cost of buying at Dawn and not the reference point of Empress and the demand charge for the unutilized capacity would be recovered later through the deferral account.

3.2.2. Reporting

Over the last few years, the Board and intervenors have learned a considerable amount about the importance of understanding gas supply, storage and the accounting for these services by natural gas utilities. While some recent focus has been on Union Gas, given the evolutions that are occurring in the transportation market, we respectfully submit that it would be in the public interest to have an increase in transparency in these areas for EGD. While some of the gas supply information may be available through the QRAM process, the constrained time frames associated with the ostensibly mechanistic process does not afford the opportunity for effective discovery.

As intervenors collaborated with EGD on agreements and reporting to allow an expedited approval of its move to FT contracting and the associated reporting[43], it was clear that we were trying to create reporting to afford transparency in an area where there was previously little. In fact, EGD and intervenors recognized that in the last paragraph of Issue 1 of the Settlement Agreement[44]:

[43] Transcript Day 8 Oral Hearing, page 4, line3 to page 5, line 21
[44] Exhibit N1, Tab 2, Schedule 1, page 7

"The parties acknowledge that, as further experience is gained and with the prior agreement of Enbridge and interested parties, the nature of the information to be provided and the frequency of the reporting specified herein can be altered."

3.2.3. Storage Level Reporting

It is the recognition of this growing understanding of the need for transparency that we requested additional information related to storage to assist in our assessment of how EGD's on-going execution of the plan affected ratepayer risks. After considerable dialogue with EGD, FRPO formalized its request for additional detail of transportation and storage parameters prior to the oral hearing[45]. In our request, we were trying to establish reporting that would allow an assessment of how EGD was managing its transportation to meet the variable market requirements of its system.

One of the key metrics in gas supply planning and execution is targeting and maintaining storage levels. As confirmed by EGD's testimony[46]:

MS. CONBOY: And is this a typical profile that I would see if I looked at other years? I mean, understanding -- give or take, but...

MR. SMALL: Pretty much. Pretty much. Yeah, you follow the same premise that you are going to try to maintain a storage balance throughout the early part of the winter so you can maintain that higher deliverability out of storage and then try to get it down to a reasonable number at the end of the withdrawal cycle as you can, and then you would start to fill back up.

[45] Exhibit K8.1 FRPO letter to Board Secretary submitted February 15, 2014
[46] Transcript Day 8 Oral Hearing, page 27, line 20 to page 28, line 5

One year to the next, there may be slight differences in your injection pattern, in the summer, for example, but ultimately, at the end of the injection cycle you want to be full so you are ready for the next winter.

The description above provides the Board with EGD's viewpoint on the importance of managing the balance in storage, enough in the winter, not too much in the summer. In our request for enhanced reporting[47], we had asked for both actual and targeted storage levels for each month. In EGD's response[48], Enbridge provided month-end storage level and subsequently testified that the storage level could be could be provided "each and every month".[49] However, the targeted storage level. In our view, that number is an indicator of how the plan is being executed. Later in oral examination, EGD confirmed its willingness to provide the targeted figures in subsequent reporting[50].

We submit that EGD's ready responses to on-going provision of targeted and actual storage levels acknowledges the importance of these metrics throughout the year from a gas supply plan and execution standpoint. We believe that the Board would benefit from this enhancement, not only in the current application, but also, others. Respectfully, we will reserve our submissions on application to EB-2014-0039 for that proceeding.

3.2.4. Reporting on Capacity Releases

As described above, one of the strategies to mitigate the potential cost of UDC is through eliminating the Dawn Discretionary purchases until all of the pipe capacity is fully utilized. From the EGD summary of supply[51], the total amount of potential UDC for Peak Design Day and the

[47] Exhibit K8.1
[48] Exhibit K8.2 EGD letter to Board Secretary submitted February 27, 2014
[49] Transcript Day 8 Oral Hearing, page 26, line 11 to page 27, line 3
[50] Transcript Day 8 Oral Hearing, page 28, line 7 to page 29, line 15
[51] Exhibit K8.2 EGD letter to Board Secretary submitted February 27, 2014, page 4

shift to FT was 66.1 PJ while the amount of annual Dawn Discretionary was 34.9 PJ. Clearly it is anticipated that other mitigation measures would need to be employed to strive to minimize or eliminate the UDC. One of the simpler measures is for EGD to release the capacity to the market to recover some portion of the demand cost, was addressed in oral examination. EGD called the process an "outright release"[52] to recover some value for the capacity as to differentiate that process from a Capacity Release Exchange where EGD still needs the molecule.[53] We understand that the full demand cost is unlikely to be recovered from the release except in rare circumstances. However, since all of the proceeds from that transaction are to be used for UDC reduction, we respectfully submit that it would be informative to the Board and ratepayers to know the monthly amount of capacity released and the total proceeds from those releases. By simple math, the difference between the demand charges for that capacity and the amount recovered in the release transaction should equal the UDC incurred for that month. Therefore, we would submit that this additional reporting ought not be a burden for EGD.

One of the reasons that this additional item of monthly reporting is being requested is due to a concern over how proactive EGD would be in ensuring maximum value for the released capacity. This is in recognition of the potential for conflict between the interests of the shareholder and the ratepayers in the management of the incremental FT capacity. This conflict arises from decisions that EGD's gas management personnel need to make in terms of storage fill for example. In the most recent Earnings Sharing Mechanisms and Deferral Account proceeding, EGD emphasized their use of Base Exchanges and Capacity Release Exchanges to generate revenue while still filling storage.[54] Part of the criteria emphasized by EGD in creating arguing for the Exchanges to be treated as Transactional Services was a "Third Party Service Request"[55]. In a hypothetical situation where EGD receives a third party request to land gas in the EGD franchise, will EGD staff be incented to perform an Exchange or Release of Capacity that is not planned to be filled. With all due respect and in clear non-pejorative terms, the clear incentive is available for an Exchange. If the third party was indifferent in terms of the means of landing the gas in the EGD franchise, the

[52] Transcript Day 8 Oral Hearing, page 35, lines 2-12
[53] Transcript Day 8 Oral Hearing, page 34, line 24 to page 35, line 1. A further description of that process can be found in EB-2013-0046 Exhibit C, Tab 1, Schedule 6, paragraph 28, pages 14-15
[54] EB-2013-0046 Exhibit C, Tab 1, Schedule 6, pages 12-15
[55] EB-2013-0046 Exhibit C, Tab 1, Schedule 6, paragraph 16, page 8

value available to the EGD shareholder is greater with an Exchange versus a Release. Given that under the current sharing for the TSDA, ratepayers would receive 90% of an Exchange and 100% of the Release, there may be situations where ratepayer value is maximized with the Release. To be able to consider whether there is a concern with the amount of UDC mitigated or the value received through Releases, we would respectfully submit that the Board and ratepayers would be better informed if monthly values of Releases and resulting recovery were made available for initial assessment. Recognizing that the deferral accounts will be reviewed on an annual basis, if concerned the Board and/or intervenors would be open to ask for monthly values of Base Exchanges and Capacity Release exchanges to compare value prior to the Board's determination of disposition.

3.2.5. Keep Separate Accounts to Allow Board Discretion on Future Applications

In its prefiled evidence[56], EGD states that the 2014 Design Day Criteria Transportation Deferral Account ("DDCTDA") is not needed. In spite of updating the Deferral Account evidence with the introduction of the Unabsorbed Demand Costs Deferral Account ("UDCDA"), EGD did not alter its previous evidence. It is our view, that keeping both accounts open and separate over the next few years would be of assistance to the Board in ensuring transparency in Gas Supply.

The prime driver for the increase in the risk of UDC in 2014 was the increase in rates for TCPL's STFT service. As described previously, TCPL was given full price discretion on the STFT and IT services as a tool to meet its desired revenue. However, as conceded by the EGD witnesses, that level of discretion and the resulting prices may not be in place as early as next year.[57]

In addition, the System Reliability drove in the increased need for STFT, again, as described earlier. In the last year, the OEB has provided conditional approval to a series of projects that could change

[56] Exhibit D1, Tab 8, Schedule 1 pages 7, paragraph 18
[57] Transcript Day 8 Oral Hearing, page 16, line 22 to page 18, line 7

the need for and the resulting contracting of System Reliability. Again, the EGD witness panel acknowledged the changes that were coming with the GTA Reinforcement projects that would make the review of System Reliability in the two years "quite possible"[58].

In our view, with significant uncertainty over the developments with infrastructure and decisions beyond this Board's jurisdiction, this would not be the time to close a deferral account and merge the accounting of a number of factors. To provide this Board with the discretion to determine the impact of changes with specific numbers attributable to respective issues, we respectfully submit that unless there is a compelling reason beyond "I don't think we need it", both accounts should remain open and separate.

3.3. Relief Requested

As outlined above and in EGD evidence[59], EGD and intervenors worked diligently over a short time to allow EGD to enter into FT contracts for the winter of 2013/14. The Settlement agreement outlined reporting to allow intervenors and the Board transparency on how the resulting UDC risks were being managed. Recognizing the terms of the Settlement expressly allow for the nature of the information provided to be altered[60], we respectfully request the Board to order EGD to:

- provide monthly reporting that includes storage level targets and actual levels of the prior month
- provide monthly reporting on amount of UDC-related capacity released and the revenue generated

In recognition that the Settlement Agreement was only put in place for one year and EGD is seeking a longer term approval for rates in this proceeding, we would respectfully request the Board to order EGD to:

- keep both the DDCTDA and UDCDA open and separate to allow future Board discretion

[58] Transcript Day 8 Oral Hearing, page 19, line 26 to page 21, line 11
[59] Exhibit N1
[60] Exhibit N1, Tab2, Schedule 1. page 7

- provide ratepayers with a transportation alternative assessment focused on peak day coverage for the winter of 2014/15 and subsequent winters
- meet with stakeholders to establish understanding of contracting requirements and agreement on reporting moving forward

While we considered requesting an independent assessment of the EGD gas supply planning and execution, we realize that our substantive concerns in this area emanate from the recent QRAM proceeding. As a result of recent events and our experience in this area, we would respectfully request the Board order EGD to:

- To prepare Gas Supply Plan memorandum consistent with recently Board approved practice for Union Gas[61]. Features of the Union Gas plan memorandum include:

(i) summary of the current natural gas market situation;
(ii) the results of the design day demand forecast with a discussion of the underpinning assumptions;
(iii) an overview of the current gas supply portfolio
(iv)identification of near term portfolio decisions and a description of how the Union strategy for the specific portfolio decision conforms to the gas supply planning principles, and
(v) a summary of major upstream pipeline regulatory filings and/or recent regulatory orders (e.g., RH-003-2011); physical infrastructure projects that will likely impact Union; and implications associated with gas supply basins as a high level discussion of these regulatory and market drivers in the Union gas supply plan will provide market context for Union's stakeholders.

In our respectful submission, these same features are as attributable to EGD and the Board and intervenors can benefit from the public interest benefits without the expense of an additional study in this specific area.

[61] EB-2013-0109 Decision dated March 27, 2014

4. Non-utility Storage Cost Allocations

A carry-over item from EB-2011-0354 was Non-utility Storage Cost Allocations[62]. We have been trying to address allocations of Base Pressure and Lost and Unaccounted ("LUF") for Gas over the last couple of years. In our oral examination, after significant resistance to the request to provide the mathematical computation of a prorata share for the non-utility, EGD agreed to provide the calculations[63]. The resulting undertaking[64] reiterated EGD's position on not allocating Base Pressure gas but provided the calculation of 12.4% non-utility storage of EGD storage allocation. While, we may not have sufficient evidence on the record to challenge EGD's expert testimony on the merits of incremental versus fully allocated costing, we recognize that the same expert approved Union's storage cost allocations in another proceeding that was subsequently over-turned by this Board.[65] Therefore that debate may have to be deferred to the future.

However, once again, EGD has failed to provide a response on the calculation of an allocation of LUF to the non-utility[66]. As explained in the oral examination and in the referenced IR(Exhibit I.B17.EGDI.FRPO.13), EGD does not allocate LUF to non-utility since its last study was done in 2007 before the non-utility business. Said differently, they have not studied it so it cannot exist. However, we have also received a cryptic answer in response to our follow-up in the Technical Conference[67] that seems to infer there is an allocation when others say there is no allocation. In our view, different from the allocation of assets on an incremental or fully allocated basis, this is a cost based allocation based upon activity that ought to be distributed across the storage operations.

Absent a clear answer from EGD, we respectfully request the Board order EGD to allocate 12.4% of its LUF (23,763.6 10^3m^3)[68] multiplied by its QRAM price for rate setting. In our view, this

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[62] EB-2011-0354 Settlement Agreement dated October 3, 2013, Item B6, page 12.
[63] Transcript Day 8, Oral Hearing, pages 44-47
[64] Exhibit J8.1
[65] EB-2011-0038
[66] See past inquiry filed under Exhibit I.B17.EGDI.FRPO.13
[67] Exhibit TCU3.6
[68] Exhibit D3 Tab 3 Schedule 1 page 2

imposed allocation would incent EGD to complete the necessary studies to provide transparency to this issue.

5. Site Restoration Costs ("SRC")

Like many others, we are concerned with how the SRC tends to mask the real outcomes of the EGD rates proposal. While we hold some strong views on some of the inputs, we formally support SEC's comprehensive analysis and recommendations on the issue. We also support SEC and others in the opportunity for a generic review of this issue prior to the next rebasing period.

6. Transactional Services Deferral Account ("TSDA")

At the outset of this proceeding, we were very concerned with the EGD position of keeping the TSDA amount in rates at $12M while removing the cap. Our position prior to the hearing was very similar to Board Staff submission calling for a doubling of the amount in rates to $24M with an increasing of the cap to $8M[69] given recent annual balances. However, we do have some concern with the continued evolution of the market and the pending EGD move to shorter-haul services. More importantly, as outlined above, if the current regulatory construct remains in place, EGD will be managing tens of millions of dollars of ratepayer risk in UDC. <u>If in its reply argument, EGD would acknowledge and accept the relief requested by FRPO from the Board in our Section 3.3</u>, we would urge the Board to keep the status quo for the TSDA as negotiated by all parties in EB-2011-0354. This position is premised on the understanding that if EGD can demonstrate that it is managing ratepayer UDC risk as a priority, we would support their opportunity to increase their return through proactive asset optimization with transactional services.

[69] Board Staff Submission dated April 15, 2014 pages 53 and 54.

Costs

We respectfully submit that the Federation of Rental-housing Providers of Ontario has acted responsibly in its intervention in this proceeding and respectfully requests that it be awarded 100% of its reasonably incurred costs in connection with this matter.

All of which is respectfully submitted on behalf of FRPO,

Dwayne R. Quinn

Principal

DR QUINN & ASSOCIATES LTD