EB-2012-0451
EB-2012-0433
EB-2013-0074

IN THE MATTER OF an application by Enbridge Gas Distribution Inc. for: an order or orders granting leave to construct a natural gas pipeline and ancillary facilities in the Town of Milton, City of Markham, Town of Richmond Hill, City of Brampton, City of Toronto, City of Vaughan and the Region of Halton, the Region of Peel and the Region of York; and an order or orders approving the methodology to establish a rate for transportation services for TransCanada Pipelines Limited;

AND IN THE MATTER OF an application by Union Gas Limited for: an Order or Orders for pre-approval of recovery of the cost consequences of all facilities associated with the development of the proposed Parkway West site; an Order or Orders granting leave to construct natural gas pipelines and ancillary facilities in the Town of Milton; an Order or Orders for pre-approval of recovery of the cost consequences of all facilities associated with the development of the proposed Brantford-Kirkwall/Parkway D Compressor Station project; an Order or Orders for pre-approval of the cost consequences of two long term short haul transportation contracts; and an Order or Orders granting leave to construct natural gas pipelines and ancillary facilities in the City of Cambridge and City of Hamilton.

BOMA's Submissions

Introduction

Union has two applications, EB-2012-0433, "Parkway West", in which it requests leave to construct, under sections 90 and 91 of the Ontario Energy Board Act (the "Act") the Parkway West station, including the necessary pipeline facilities to, within, and from, the station and related infrastructure, as well as a 44,500 hp compressor station, Compressor C. It has also applied, under section 36 of the Act for pre-approval for recovery of the cost consequences of the Parkway West facilities from ratepayers, effective January 1, 2015. This pre-approval of facilities' cost recovery in rates is not normally part of a facilities application. Union has also filed an application, EB-2013-0074, for approval under sections 90 and 91 of the Act for leave to construct an NPS 48 pipeline from the existing Brantford valve site to the Kirkwall Transfer Station, a distance of 14 kms, and for leave to construct a second 44,500 hp compressor (the "proposed Parkway D Compressor"), including measurement and associated facilities at the proposed Parkway West Station. As part of that application, Union has also applied, under section 36 of the Act, for pre-approval of the cost consequences of both the pipeline and the compressor, in rates, and for pre-approval of the cost consequences of two long term short haul contracts with TCPL to move gas from Parkway to Union's customers in its Northern and Eastern Delivery Areas.

Enbridge has applied to the Board for leave to construct what it calls the Greater Toronto Area Project (EB-2012-0451). The details of the Enbridge proposal are contained in EB-2012-0451, Ex A, T2, Sch 1, which requests OEB leave to construct both transmission and distribution facilities. The Board decided to deal with these three applications in one proceeding.

At the same time as this proceeding has taken place, TCPL, Union and Enbridge, as well as Gaz Metro, have been engaged in a lengthy negotiation to restructure the natural gas transportation business in Ontario and Quebec. The negotiations dealt with, among other things, the levels of future TCPL tolls, both long haul and short haul, the segmentation of TCPL's rate base for tolling purposes into three segments, the Eastern Ontario Triangle ("EOT"), the Northern Ontario Line ("NOL") and the Prairie Line, TCPL's commitments to construct required short haul transmission facilities in Ontario, access by EGD, Union and Gaz Metro to short haul transportation in the EOT on a reasonable commercial basis, payment by the three LDCs (through higher tolls) of compensation to TCPL for mainline stranded costs as a consequence of LDC (and other) mainline shippers replacing long haul with short haul transportation and restoration of the EOT's revenue requirement to support full cost recovery including a 10.1% return on equity. The four parties signed a Settlement Term Sheet on July 13, 2013, and a Settlement Agreement on October 31, 2013. TCPL proposes to take the Agreement to the TCPL Tolls Task Force to obtain the agreement of other shippers and stakeholders, and to file the Agreement with the National Energy Board ("NEB") before January 31, 2014. Given that the Settlement Agreement changes many of the provisions of the NEB's landmark decision, RH-003-2011, the NEB must approve the Agreement for it to become effective. No one knows, at this point, what the NEB will do with the application, but, given its impact on the NEB's recent decision, and the variety of interests typically involved in NEB proceedings, it will likely not be an "easy" case.

BOMA is of the view that the leave to construct application for the various facilities applications of Union and Enbridge are all materially affected by the recently arrived at Settlement Agreement and the disposition of it by the NEB. BOMA will address these impacts as part of its discussion of each of the utilities' applications.

Moreover, the Settlement Agreement is important in its own right and is, and should be, of great interest to the Board, because it represents a change in the overall regulatory structure, in which the gas utilities that it regulates, and TCPL, which the National Energy Board regulates, operate. The Board should be interested in the basic "deal" embedded in the Settlement Agreement, which is the commitment of Union and Enbridge (along with Gaz Metro) to pay increased tolls to fund TransCanada's mainline system's stranded costs (its deficiency) for a period of six years from January 1, 2015 to December 31, 2020, in other words, to remove the shortfall between its revenue requirement and realized revenues, and to restore and maintain TCPL's ability to recover its cost of service on the EOT for the next sixteen years. The total transfer of funds has not been disclosed by TCPL and the LDCs but the amount, likely in the order of $2 billion, when compared with the compliance tolls, payable through higher tolls, amortized over a sixteen year period, from 2015 to 2030. In return, TCPL agrees to offer short haul service, at the agreed to tolls, on the Eastern Triangle, to allow mainline shippers to convert their existing TCPL long haul service to short haul service, and to build when required to meet the increased demand for short haul service, subject to a commitment of the LDCs to maintain a reduced level of long haul capacity on TCPL until December 31, 2020, and to agree to a ROE of 10.1%, for the period 2015 to 2020, down from the 11.5% ROE approved by the NEB in RH-003-2011. The agreed tolls will recover the cost of service of the Eastern Triangle, and will fund the necessary bridging payments to TCPL, from 2015 until 2030. By using TCPL's short haul service, Union and Enbridge (and Gaz Metro) are able to increase the amount of gas in their portfolios from basins other that Western Canada in their system gas portfolios, and, they allege, reduce their landed cost of gas.

The basic commercial deal was stated in the parties' own words on page 9 of the Settlement Term Sheet, in a commitment they made to:

> "File a joint letter at the NEB regarding the framework necessary to allow for market access for new supplies in eastern Canada and new capacity requirements on the eastern TransCanada Mainline (EOT) in a manner that balances market access with cost recovery associated with new infrastructure investments. The LDCs commit to remain consistent with the principles of this Term Sheet, in which the LDCs support TransCanada having a fair opportunity to recover its costs, including lost revenue associated with shifts from long haul to short haul service, over an appropriate period of time. TransCanada commits to remain consistent with the principles of this Term Sheet, in which TransCanada supports the need for market access to new supplies under a reasonable and fair tolling framework".

Similar words were used in the Settlement Agreement.

As noted, this is a very important Agreement, and to characterize the nature of the Agreement as a simple toll increase, to be considered in the appropriate QRAM proceeding, as the utilities have tried to do, is disingenuous. It is clearly much more than that.

It is, among other things, a substantial rewriting of the National Energy Board's ("NEB") recent RH-003-2011 decision, itself, a major departure from the NEB's traditional approach. Union, Enbridge and TCPL are all agreed on this point. As Mr. Isherwood noted during the September 13th Technical Conference, in answering a question about the impact of the Settlement Agreement on one important feature of the NEB's RH-003-2011 decision, the Toll Stabilization Adjustment Amount ("TSA"):

> "This framework actually replaces the existing framework, so the TSA would disappear" (T.C., p17).

The Settlement Agreement provides that if the National Energy Board does not approve the Agreement in its entirety, unless all parties agree to accept the Board's decision, the Agreement is terminated (s 2.1; s 16.2). All parties must agree to appeal or request a review and variance of a decision. So the parties do not know whether they have a deal until the NEB has issued its decision, and the parties have decided to accept it, or all the parties agree to launch a second application, and the NEB approves the second application, and if the NEB fails to approve the second Application in its entirety, the Settlement Agreement is terminated, unless all the parties accept that decision (Settlement Agreement, Article 7). These provisions essentially replicate the Term Sheet termination provisions, and the consequences are broadly similar, namely, that if the NEB does not approve the Agreement or all parties cannot agree that what the NEB did approve was acceptable, the parties' proposed restructuring of the market is dead, and presumably any attempt by LDCs to replace long haul with short haul transportation without compensation for TCPL's "lost revenue" would be stymied by TCPL.

The Agreement also provides that Enbridge will not allocate capacity on its Segment A Transmission Pipeline bid into the open season that closed September 6, 2013. That open season has been terminated (s 11.1(c)). If and when the parties obtain an NEB decision with which they all agree, Enbridge agrees to hold a new open season for the 1,200 GJs/day of transmission capacity, which will be STAR compliant and TransCanada will bid to contract for such capacity, "either directly or through an assignment of capacity from Union and Gaz Metro (or any other prospective shipper), subject to any required OEB approval" (ss11.1(d)). There has been no explanation by TCPL or the LDCs as to why these sections were included, or how to square the circle of STAR compliance with TCPL obtaining all the transmission capacity.

Given its complexity, and the fact that it represents a rewriting of much of that Board's RH-003-2011 decision, it is not clear whether the NEB will approve the agreement altogether, turn it down, or approve it with modifications as it did TCPL's application RH-003-2011. And it is unlikely the NEB will issue its decision until the second quarter of 2014. The important point for the LDCs' current applications is all parties agreed that if the Settlement Agreement is not approved in its entirety, unless all parties agree to accept it, as modified, or agree to make a second application to the Board, and the NEB approves the entire amended version of the Settlement Agreement in a second proceeding, or if it makes modifications, unless those modifications are accepted by all of the parties, the Agreement is terminated, and the parties are back in the "state of war" or stalemate that existed before the negotiation of the Settlement Term Sheet. The commitment in the Settlement Agreement of the parties to continue seeking a solution in those circumstances is aspirational only, and is not a legal obligation.

The Board will recall that, in this environment, TransCanada had refused to build any new short haul capacity on its system unless the LDCs agreed to what they considered to be clearly punitive tolls, tolls that were equal to or higher than TCPL's long haul tolls. Were Enbridge in such circumstances to relaunch an open season that was STAR compliant, TCPL would likely file a new lawsuit to prevent it from allocating capacity, unless TCPL received proper compensation. Note that the Settlement Agreement prevents EGD from allocating capacity in its current open season.

Given this uncertainty, it does not make sense for the Board to approve either the Enbridge or Union transmission related proposals, Segment A, Brantford-Kirkwall, Compressor C, and Compressor D, until the proposed new structure is confirmed. In other words, it is premature for the Board to allow Parkway West to proceed, save for the land acquisition, supporting infrastructure, and addition of the Enbridge city gate. Moreover, Union's proposed Compressor D, Brantford-Kirkwall looping and Enbridge's transmission line (Segment A) should not be approved pending a final binding Settlement Agreement between TCPL and the LDCs that is approved by the NEB. The Board might invite parties to reapply once the regulatory environment has stabilized.

The Board should approve the North-South portion of Segment B of the GTA Project, which, taken together with larger and more targeted DSM measures, should address EGD's Station B issue, and permit adequate gas supplies to reach the downtown Toronto core. That appears to be the immediate issue.

The last point is based on Enbridge's evidence, that if they were to look at a ten year customer growth horizon for the GTA region, the minimum pipe build required to supply ten years of growth in the GTA system would be the north-south piece of the Segment B (I.A1.EGD.APPRO.3, p1). BOMA reads this to mean that the construction of the Buttonville to Shepherd Avenue loop would allow sufficient gas to reach the downtown core at sufficient pressure to serve customers in that region going forward. Enbridge does not state in its IR response whether pressure on Don Valley line is reduced or remains as is.

BOMA will discuss each of the applications separately, beginning with Enbridge's GTA project, both its transmission line (Segment A) and its proposed distribution expansion, Segment B, and the smaller part of Segment A. It will then move to Union's Parkway West and Brantford/Kirkwall and Compressor D proposals.

In each case, it will discuss interdependencies among the projects and how each proposal will or may be impacted by the Settlement Agreement, the National Energy Board's future decision on that Agreement, and the reaction of the parties to that decision.

BOMA will also highlight some aspects of the Settlement Agreement that affect and constrain the parties potential courses of action after an NEB decision. Suffice it to say at this point, that in the event the NEB were to approve the Settlement Agreement with modifications, all four parties would have to agree to accept each modification of the Agreement. If not, the Agreement would terminate, and the commercial stalemate and regulatory battles would resume.

<u>Enbridge GTA Project</u>

(a) The Transmission Pipeline

Enbridge proposes to build a 27.4 mile 42" transmission pipeline, with a total capacity of 2,000 TJs/day from Union's proposed Parkway West Station to Albion, an existing Enbridge Station

("Albion Transmission Line"). The larger part of the capacity, 1,200 TJs/day would be a transmission line which would run in parallel, and several miles south of the TCPL mainline. For the first five miles of its route, from Parkway to Bram West, it would run virtually adjacent to the TCPL line. Enbridge proposes to offer transmission service to the market, commencing in 2015, initially to Union and Gaz Metro, to transmit gas from Parkway to their customers in Northern and Eastern Ontario, and in Quebec, respectively. The smaller part of the line, 800 TJs/day will be a distribution line, to facilitate Enbridge's GTA project. Enbridge had proposed to commence transmission and distribution service on November 1, 2015, although that date does not seem reasonable at this point. The most recent estimate of the cost of the transmission line is $225 million. The updated projected cost for the entire GTA project is $686.5 million, which appears to be about evenly split between transmission and distribution, although Enbridge did not break out its numbers on that basis (Ex. C, T2, Sch 1, pp1-6). In the Settlement Agreement, TCPL has agreed to support the Enbridge transmission line, provided it has the opportunity to acquire all of the transmission capacity either by assignment from other shippers or in some other, as yet defined, manner. Enbridge requires only 600 TJs/day distribution capacity now for its GTA project. However, it proposes to fill the distribution pipe with 800 TJ/day of gas and leave 200 TJs/day excess capacity at Parkway Consumers, which it will gradually utilize over a ten to twenty year period (I.A1.A3.EGD.BOMA.18(a)).

In order to transport Union and Gaz Metro gas from Albion onward to the TCPL mainline in Vaughan, TCPL has agreed, as part of the Settlement Agreement to construct the "King's North" pipeline, a 36" 13 mile pipeline running from Enbridge's Albion Station northwest to the mainline at Vaughan, at an estimated cost of $60 million, to commence service on November 1, 2015. The initial capacity of that line is estimated to be 450 TJs/day (T.C. Sept 13, pp 35 and

176), although it will only carry 385 TJs/day commencing November 1, 2015 forward. TCPL has not yet held an open season for capacity starting November 1, 2016. As part of the Settlement Agreement, TCPL is proposing to resurrect the results of its 2012 open season for additional Parkway to Maple capacity, in which that 385 TJs/day of capacity was allocated to Gaz Metro and Union (subsection 11.1(a)).

Enbridge held an open season for capacity on its proposed Albion Transmission Line in July and August of this year for service beginning November 1, 2015. It closed on September 6, 2013. It received bids for only 385,000 GJs/day starting November 1, 2015, from Union and Gaz Metro, and a further 385,000 GJs/day commencing November 1, 2016 from as yet undisclosed parties. Nonetheless, it has stated that it needs to commence construction of both the transmission line and distribution components of the line, as soon as the OEB approves its application, so as to have the line in-service for November 1, 2015. That statement is odd, because Enbridge has agreed in the Settlement Agreement not to allocate the capacity sought by Gaz Metro and Union, in its recent open season (subsection 11.1(c)), and to hold a new open season once the Settlement Agreement is approved by the NEB (subsection 11.1(d). It, therefore, intends to begin construction even before it allocates capacity on the line, let alone enter into Precedent Agreements and Contracts with its shippers.

Enbridge makes its position clear in several places in the evidence, including in the following exchange (T.C. Sept 13, p189):

> "MR. BRETT: Now, did I understand you to say this morning that you would actually start to construct the line prior to signing those shippers up to contract, to firm contracts?
>
> MR. GRIDHAR: We are seeking approval of the NPS 42 Segment A in the facilities application.

> MR. BRETT: Yes?
>
> MR. GRIDHAR: And we are seeking approval from the OEB before the end of this year. The OEB would approve our application. We would begin constructing immediately because we need to have the facilities in place for November 1, 2015.
>
> MR. BRETT: Whether or not you've signed contracts at that point?
>
> MR. GRIDHAR: Correct. That is correct."

TransCanada stated that it would never commence construction without signal contracts (T.V. 9, p62). Enbridge's behavior is unprecedented in the pipeline business and it is imprudent.

More astonishing still, Enbridge asserts that its ratepayers should pay for any unused capacity in the transmission pipeline (T.C. Sept 13, p 188). EGD proposes to include all the 1,200 GJs of transmission capacity in its revenue requirement, even in the years when it is operating at a fraction of its full capacity, or in a year when it has no shippers at all. It is already clear that there would be substantial excess capacity in 2015 and 2016, and there is no clear indication as yet as to what shippers will contract for service in later years. In fact, as noted above, in the Settlement Agreement, Enbridge agrees not to allocate any of the capacity from its recent open season, and to hold a new open season once the NEB has approved the Agreement.

BOMA views this transfer of risk to shareholders as totally unacceptable. If the Board grants leave to construct the transmission component of the line, it should contain a condition that Enbridge shareholders should be responsible for excess capacity in these circumstances.

Moreover, Enbridge has stated that it will proceed to build the transmission line before TransCanada obtains NEB approval to construct its proposed King's North line, which would carry shippers' gas (Union's and Gaz Metro's initially) destined for points east and north of the GTA from Albion to the TCPL mainline at Vaughan. As the Board is well aware, any shipper, be it Union, Gas Metro or a northeast US utility, which contracts for gas on Enbridge's proposed Albion transmission line would require TCPL's proposed King's North line to move its gas to the intended destination, and would make completion of the King's North line (or at least NEB approval of the line) as a condition precedent, to implementation of a Precedent Agreement and transportation contract with Enbridge. Enbridge's position to proceed immediately while holding its ratepayers responsible for unused capacity is imprudent. It is even more unacceptable, given the fact that Enbridge, through its inept handling of the implementation of its "transmission strategy" has been responsible for much of the elongation of the proceeding. As an aside, for Enbridge to now complain about the fact that it is "being deprived the opportunity for approval" because of the length of the proceedings, which it did a few weeks ago, is more than passing strange.

TransCanada has not yet commenced its own 2016 open season, has not yet applied to the National Energy Board for approval of the King's North line or the Settlement Agreement, and has not provided any firm indication of when it expects NEB decisions of the King's North proposal or the Settlement Agreement. The fact that TransCanada has not yet filed the Settlement Agreement with the NEB, and will not do so until as late as January 31, 2014, creates additional uncertainty. TCPL will need the NEB decision on the Settlement Agreement to determine, inter alia, whether the King's North project is a viable option.

Second, BOMA does not support EGD's entry into the transmission business. Enbridge is not in the transmission business and never has been. It has admitted that it has had little experience with the use of compression in its system. Its inexperience in that business is evident in the missteps Enbridge has made since it filed its initial transmission submission in January 2013. First, it conceived the idea of a line, jointly owned with TransCanada, and then abandoned that position once it realized that one pipeline regulated by two regulators would not be workable. It then proposed in its initial filing, made in January 2013, to construct a 36" pipeline, which it would own, and in which it and TCPL would each hold 600 TJs/day of capacity. This arrangement was made without informing Union Gas or Gaz Metro, with whom Enbridge and TCPL had been carrying out tri-party discussions. In February 2013, Enbridge entered into a Memorandum of Understanding ("MOU") with TransCanada, which gave TransCanada the exclusive right to the transmission capacity of pipeline during the term of the MOU and for ten years after it expired or terminated. The MOU clearly contravened the OEB's STAR Guidelines, a position that Enbridge first denied, then later accepted, but only after Union and Gaz Metro had filed a motion with the Ontario Energy Board, asking it to dissolve the MOU, and filed a complaint with the National Energy Board that the MOU contravened the NEB Act.

Before these motions were completely litigated, Enbridge did a 180 degree turn and terminated the MOU with TransCanada. TransCanada responded by proposing an open season for short haul capacity on its Ontario System (the "EOT") at tolls equivalent to, or higher than, its existing long haul tolls, and well above the compliance tolls authorized by the NEB in June 2013. TransCanada also sued Enbridge for $4.5 billion in damages, and for an order requiring Enbridge to perform its commitments in the MOU. BOMA is of the view that Enbridge was imprudent, in its negotiations with TCPL with respect to the MOU, in allowing TCPL exclusive access to the transmission line, which Enbridge knew or ought to have known contravened the STAR Guidelines. There is simply no credible interpretation of the STAR Guidelines, which would have permitted that arrangement. The resulting regulatory chaos and stalemate over the spring and early summer of 2013, up until the execution of the "Settlement Term Sheet" in July delayed the OEB proceedings, exposed Enbridge to serious risk of loss and, BOMA suggests, likely placed the LDCs in a weaker bargaining position opposite TCPL. The ensuing Settlement Agreement between the eastern LDCs and TCPL favours TCPL, in that the LDCs have agreed to accept tolls at a level which TCPL will pay down the stranded costs of TCPL's Northern Ontario time and Prairie line for a six year period, and guarantees TCPL full cost recovery, including a return of 10.1% on the mainline until December 31, 2020, and on the EOT segment of the mainline until 2030, in return for TCPL agreeing to allow them to switch from long haul transport to short haul transport further penalty. Despite their protestations, the LDCs had to buy their freedom from TCPL, and they paid a steep price for it. They justify it in part by an interpretation of the RH-003-2011 decision that would have them absorb any shortfalls in TCPL's revenue, otherwise, their interpretation is speculation. The NEB might just as likely disallow TransCanada costs in that situation. They certainly delayed the hearings. Finally, Enbridge increased the size of its pipeline from 36" to NPS 42, which materially increased its cost ($54.5 million, J6.14) without little justification. At the same time, they seemed to argue that the 42" line would be used for distribution purposes only, as it could operate at a lower pressure. But surely, if the Board were to not grant leave to construct the transmission line, it would not be reasonable for Enbridge to seek leave to construct a 42" 27.5 mile distribution line.

Third, BOMA believes that Enbridge does not need to build a transmission line to realize several of its stated objectives for the GTA project, including to save on upstream transportation lower costs, to serve increased loads, flexibility, decrease its operational risk, increase the reliability of gas supply, including access to the Marcellus and Utica basins, and diversity of entry points.

Fourth, Enbridge already has access to multiple basins in the US through its deliveries at Dawn and contracts with Union to move gas from Dawn to the GTA, and its planned contract with TransCanada to move Marcellus gas to its "Parkway/Consumers" city gate (Enbridge CDA) through TCPL's domestic line (Hamilton line) in an amount of 200,000 GJs/day beginning November 1, 2015 (Ex. 1, A1.EGD.BOMA.1, p3). Enbridge already moves gas from several US basins to its franchise area through its extensive transportation contracts with Union Gas. Enbridge is the largest single shipper on Union's Dawn to Parkway transmission system. The gas enters Enbridge system mainly at "Parkway Consumers" but a smaller portion enters at Lisgar, and a smaller portion is compressed by Union at Parkway, and moved through the TCPL mainline to Enbridge's more easterly city gates, such as Victoria Station.

Fifth, Enbridge's evidence states that one of its objectives in proposing the GTA project was "to displace less secure elements of its supply portfolio with more reliable supply, while reducing gas supply costs" (Ex A, T3, Sch 7, p 1 of 19). Union has made similar claims for its Brantford-Kirkwall pipeline loop and Compressor D.

BOMA is of the view that the claims by Union and Enbridge that gas supply would be more reliable if they were to build the GTA and Brantford-Kirkwall facilities are not supported by the evidence. The LDCs must support the projects by something other than access to more reliable gas supplies, given recent developments in North American gas markets. Union agreed that it had no difficulty contracting for gas in Western Canada (T.V2, 75), and continues to do so for deliveries through Alliance/Vector and TCPL. Enbridge is in a similar position.

There is a great deal of gas in western Canada in the rapidly developing shale and tight gas reserves in the Montney, Horn River, and Liard Basins, the Cordova Embayment, and Duvernay Play, to name a few, certainly enough gas to supply to eastern Canada, the oil sands, and the proposed LNG export projects. In this respect, the analysis provided by the utilities was highly disingenuous, if not deliberately misleading. For example, Enbridge's and Union's prefiled evidence (for example, EB-2012-0451, Ex. A, T3, Sch 5, p16) showed a graph from a dated (2012) AEUB report, showing declining conventional gas reserves in Alberta, and declining gas available for export, conveniently ignoring the burgeoning supplies of non-conventional, i.e. shale gas and tight gas, which have grown rapidly in the last five years and have attracted investments from around the world. A very recent November 2013 study, Energy Briefing Note - The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta, published jointly by the National Energy Board, the British Columbia Oil and Gas Commission, the Alberta Energy Regulator, and the British Columbia Ministry of Natural Gas Development concluded:

> "The Montney's marketable unconventional gas resource is one of the largest in the world. While most of it is located in British Columbia (Table 2), Alberta's share is still large (Table 3). To further illustrate the size of the Montney, total Canadian natural gas demand in 2012 was 88 billion m^3(3.1 Tcf), making the Montney gas resource equivalent to 145 years of Canada's 2012 consumption. In addition, the Montney is already considered one of Canada's most <u>economic</u> gas plays. Even though it is only in the early stages of development, its 2012 production rose to an average of 48.6 million m^3/d (1.7 Bcf/d) out of total Canadian marketable gas production of 392.7 million m^3/d (13.9 Bcf/d). It is expected that Montney gas production will continue to increase and grow its share of Canadian production (our emphasis).
>
> By combining this marketable gas estimate with prior assessments, including the most recent estimates of western Canadian ultimate potential for <u>conventional</u> natural gas, the total ultimate potential in the Western Canada Sedimentary Basin (WCSB) has more than doubled to 23,249 billion m^3 (821 Tcf) (Table 4). Out of this total, 17,898 billion m^3 (632 Tcf) is remaining after cumulative production to year-end 2012 is subtracted. The ultimate potential for natural gas should be considered an estimate that will evolve, likely growing over time as additional unconventional potential can be found in unassessed shales, such as those in the Liard Basin of British Columbia and the Duvernay Formation of Alberta. Overall, Canada has a very large remaining natural gas resource base in the WCSB to serve its markets well into the future."

As the Board is aware, the Montney is only one of several unconventional gas basins being developed in western Canada.

In BOMA's cross-examination of the Joint Panel 1, it cited the National Energy Board's statement, at p162 of its recent RH-003-2011 decision, that:

> "We are of the view that unconventional sources of gas, such as those in the Montney, Horn River Basin and Cordova Embayment will constitute the majority of future discoveries. We accept TransCanada's submission that these unconventional sources of natural gas will more than offset the long-term decline in conventional production from the WCSB. Considering all factors, we find that the risk that natural gas supply will not be <u>economically available and accessible</u> to the Mainline is lower today than it was when the Board last assessed the Mainline's business risk in RH-2-2004 Phase II. As a result, we believe supply risk to be lower than the last time it was considered for the Mainline" (our emphasis).

The essence of the Board's conclusion is that TCPL will not have a serious supply risk going forward. In other words, TCPL will get enough gas to supply whatever eastern Canada requests. The LDCs may not wish to pay that toll, or think that they can get a better landed price of gas by contracting for gas in, and pipeline transportation from, other supply basis, be they in the Rockies, US Midwest, US Gulfcoast, or Marcellus and Utica Shales or others. That is their choice. The point is there is enough gas in western Canada for them. That is what the NEB was saying, and no party, including Union's expert, Mr. Herring, took issue with that conclusion, in any credible manner.

Sixth, and perhaps most important, there is no longer a need for Enbridge to build transmission in the Parkway to Maple corridor. TCPL can do it. In the Settlement Agreement, TCPL has moved off its earlier refusal to offer short haul transmission service in the EOT at tolls acceptable to the LDCs for existing and new short haul service. It has now agreed to build additional short haul capacity on the EOT, as required, for shippers that wish to switch from long haul transportation to short haul transportation on TCPL (Settlement Agreement, sections 2.2, 2.3(b), (c), and 9.2). To that end, as noted above, it has agreed to resurrect its 2012 open season for 2015 service and provide Union and Gaz Metro the capacity it awarded them at that time, provided they sign fifteen year contracts (Ibid, subsection 11.1(a)). It has also agreed that, to hold an open season this fall for all paths on the Mainline System, including the EOT paths, for service November 1, 2016 at tolls set out in the Agreement (Ibid, subsection 11.1(b)). In other words, TransCanada has agreed to return to its historical role as transmitter of gas in Ontario, wherever the gas happens to originate.

TransCanada has demonstrated their willingness to build on request by its ongoing work to plan the construction of the King's North line, and its upcoming open season (Ibid, subsection 11.1(h)).

The Settlement Agreement, if approved by the NEB, change many parts of the NEB's RH-003-2011 decision, including those parts which made it unprofitable for TCPL to build new capacity. <u>If this happens, there is no need for Enbridge to burden its ratepayers with the cost and risks inherent in building a large transmission line, particularly in a manner and under terms and conditions that will visit incremental risks on its ratepayers</u> (our emphasis). EGD is a distribution utility, not a transmitter. It has admitted to having little or no experience with compressors on its system. TCPL has indicated during the hearing that, in the event the Board declined to grant Enbridge's leave to construct a transmission pipeline, it would work with its potential shippers, including Enbridge, to develop other options (V9, p73, lines 5-10). If the NEB agrees to the Settlement Agreement, TCPL can and will build the necessary EOT transmission, to remove the current "Parkway to Maple" bottleneck. It will be legally bound to do so, and given its long experience with the construction and operation of transmission lines, it will do it more cost effectively and with less risk than Enbridge. Gas Transmission is TCPL's core business.

Exactly how and in what sequence TCPL would expand capacity east of Parkway would be decided in conjunction with discussions with its shippers. TCPL has already demonstrated its willingness to jointly own a pipeline that would run in the Bram West to Albion corridor, already used by an existing Enbridge very high pressure distribution line, NPS 36 Parkway North. That would have been the path of the previously considered, jointly owned line. TCPL may choose to build on that route. In that event, Enbridge could simply take delivery at Albion of the 600 TJs/day or 800 GJs/day it wishes to move from Parkway to Albion, without having to construct transmission facilities or significant distribution facilities, other than a modification to Albion to make it a gate station. TCPL could build to move gas from Bram West to Albion, and then on to the Eastern Mainline (King's North). Alternatively, TCPL could build a transmission line from Vaughan to Albion, along the King's North route. These options were apparently not seriously considered by Enbridge, nor the subject of any comparative cost analysis that was filed in evidence. Enbridge's complaint that Albion was not a receipt point in the TCPL tariff that could be easily adjusted by the NEB, at TCPL's request. Nor did Enbridge's responses to their lawyer's re-examination diminish advantages of TCPL building the Albion transmission line. If TCPL built and owned the line, the TCPL line would not be integrated into Enbridge's distribution system. Rather, it would be part of the TCPL mainline, and Enbridge would be a shipper on that line. Albion would simply become an additional delivery point. Balancing requirements should be no more complex than at any pipeline/LDC gate station, and can be resolved contractually, through amendments, if necessary, to the TCPL tariff (T. V6, p166).

These investments by TCPL and Enbridge would overcome what Enbridge has described as a bottleneck on its NPS 36 line from Parkway Enbridge to Albion. However, the evidence suggests that Enbridge has not considered these options in detail. While it would have been logical to discount the "TCPL-build" options if Enbridge were analyzing the matter after terminating the MOU, or during the earlier period before and just after the NEB's RH-003-2011 decision, when TransCanada could not, in its view, profitably remedy the Parkway to Maple bottleneck, as noted above, the Settlement Agreement <u>requires</u> TCPL to build the necessary capacity, and, given that TCPL and the LDCs have had negotiations around such an agreement for at least a year, it would have made sense to evaluate these options in any event (our emphasis). Enbridge has not re-examined the options in light of the Settlement Agreement, and its earlier review of options, in 2011 and 2012 were greatly influenced by the need to overcome the constraint between Parkway and Maple (EB-2012-0451, A, T3, Sch 7, pp5-6 of 9). The idea of having TCPL build the necessary transmission capacity to Albion or otherwise, and have Enbridge build only any distribution connection to TCPL that was necessary, seems not to have been considered. The assumption all along seemed to be that Enbridge would <u>have to build</u> a transmission line, which it would at least partly own with a third party, either Union or TCPL. Nor was DSM considered an alternative, even though it was reasonably obvious that it would assist with customer growth (see below).

Seventh, BOMA's view is most, if not all, of the operational risk reductions, and additional flexibility benefits and growth benefits that Enbridge seeks could be achieved by building Segment B alone at this time. Enbridge's evidence is that Segment B, if built, without even the distribution component of Segment A, would accommodate forecast growth requirements in the XHP network in the GTA.

Enbridge does not require the Segment A transmission/distribution line of 2,000 TJs/day capacity to meet its load growth in the GTA, given the contribution of an enhanced DSM program, its additional capacity at Lisgar, and its ability to either have TCPL build to Albion in some fashion or itself build a smaller distribution line from Albion to the TCPL mainline in Vaughan.

Eighth and finally, contrary to what Enbridge stated in its reply to BOMA's IR (I.A1.EGD.BOMA.26), Enbridge does not have to build a large transmission line to obtain "a greater degree of control of its gas supply".

Enbridge maintains control of its gas supply portfolio by contracting prudently with gas suppliers, be they producers or marketers, in a diversity of supply basins, over different time periods, and by contracting prudently with different transmission pipelines, eg. Union, TCPL, Alliance, Panhandle, et al, to move that gas, from its point of purchase to its franchise area. Occasionally, it will purchase a "delivered service" where its vendor agrees to deliver the gas to an Enbridge City Gate or to Dawn. It does not need to own transmission lines itself to do this. The ownership of a transmission line does not materially enhance its ability to "control" its gas supply.

<u>The Distribution Line Part of Segment A</u>

Enbridge has reserved 800 TJs/day of capacity on the proposed 42" line for its own use in the GTA. This is a distribution line. In the event TCPL's proposals to serve Albion were too expensive, Enbridge could build a distribution line from Albion to Vaughan to allow it to access more gas at Vaughan. It could use the King's North path which in the scenario described above, would not be required. Note that Enbridge's evidence states that it wishes to replace its current

400 TJs/day STFT TCPL mainline capacity effective for 2014 only[1]. This requirement is not to serve incremental load, but to change its current upstream transportation arrangements. TCPL's STFT service is not renewable, and therefore, does not offer Enbridge sufficient transportation security, particularly in light of the oil east project. Moreover, STFT is now very expensive, since the NEB in RH-003-2011 gave TCPL complete discretion on how to price it, subject to floor price.

Going forward, Enbridge wishes to reduce its long haul transportation capacity on TCPL because Enbridge believes long haul mainline tolls from Empress (the WCSB) are currently higher than the sum of TCPL short haul, Union and US pipeline tolls from other basins, and more than offset the fact that gas commodity prices in Eastern North America are higher, in particular at Dawn, than the gas commodity prices at the AECO trading hub in Alberta.

The 800 TJs/day of distribution capacity that Enbridge wants to have at Albion, in addition, to replacing the 400 TJs/day of TCPL long haul capacity, discussed above, would also enable Enbridge to move 400 TJs/day of gas supply that it currently receives from Union at the Parkway City Gate to Albion (and Parkway compression). This gas currently flows from Dawn to Enbridge Parkway gate station, and enters Enbridge's distribution system at that point, and to a lesser extent, at the Lisgar gate station, two miles farther east on Union.

Part of the reason for moving the 400 TJs/day from Parkway to Albion is to allow room at Parkway Enbridge for 200 TJs Marcellus Gas, which Enbridge plans to access in 2015 (I.A1.EGD.BOMA.1).

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[1] Note that Enbridge has recently replaced much of its STFT 2014 capacity with long haul FT (non-renewable) capacity and filed a Settlement Agreement with the Board on October 29th to that effect, which the Board recently approved.

Parkway Enbridge is virtually full on a peak day and other cold winter days, so Enbridge currently does not have the capacity at Parkway to receive the 200 TJs/day of Marcellus Gas. Enbridge intends to leave the remaining 200 TJs at Parkway Enbridge empty (but paid for by ratepayers) and will use it up gradually as necessary to help meet the GTA's incremental demand over the next 20 years (I.A1.A3.EGD.BOMA.18). In effect, EGD plans to overcontract for distribution capacity by 200,000 GJs/day. The unutilized capacity will be paid for by ratepayers. In BOMA's view, all of that cost should be borne by the shareholders until such time and to the extent that it is filled with gas entering the GTA.

None of these changes, described above, other than the empty pipe, which will be filled over ten years to 2025, in itself contributes towards meeting Enbridge's forecast demand growth. Moreover, there appears to be no reason to move the "second" 200 TJs/day from Parkway Enbridge to Albion (and Parkway compression), as the gas is already being supplied on a short haul basis from Dawn. The move really allows Enbridge to avoid having its highly visible new distribution line twenty-five percent empty.

In summary, so long as Enbridge gets 600,000 GJs additional short haul into its system at Albion, or, in the case of Marcellus Gas, Parkway West, it has the opportunity to accomplish its upstream transportation objectives. Enbridge will be able to source additional volumes of gas from basins other than Western Canada and it will move that gas to Parkway Enbridge or to Parkway (TCPL) by either Union Gas, or the TCPL Niagara line (200,000 GJs/day), both of which are short haul routes.

TCPL capacity already exists for the incremental gas flow from Maple to Victoria Square. If additional capacity is required from Bram West to Vaughan, TCPL could build that.

Alternatively, as noted above, Enbridge could also build a smaller line from Bram West to Albion, sized just for the distribution volumes, adding such compression to the line as may be necessary.

Enbridge - Segment B

In BOMA's view, Enbridge cannot justify all of Segment B on the grounds that it is needed for customer growth in the GTA. Growth in the GTA is modest, in relation to the capacity of the proposed facilities' additions, and given the evidence filed by Enerlife on the potential for additional DSM that was not seriously challenged by Enbridge (see DSM discussion below). Enbridge's evidence is that the minimum new infrastructure to accommodate ten years of customer growth while maintaining the required minimum pressure at Station B is the proposed 7 kms of NPS 30 pipeline loop between Buttonville and Shepherd Avenue (I.A1.EGD.APPRO.3, p1), which is the "north-south" part of Segment B. This assumes no incremental DSM contribution, beyond what the current program would yield and, I believe, no pressure reductions. Such a build would allow additional volumes to flow southward on the Don Valley line to offset pressure drops along that line, while maintaining the required pressure at Station B. The volume of gas commodity flowing through the looped line would not have to materially change, other than to deflect annual organic growth offset by DSM measures, and that the volume would continue to be sourced at Victoria Square.

Moreover, BOMA does not believe that the construction of an NPS 36 line, alongside the NPS 26 Keele to Don Valley line existing, by a new NPS 36 line is necessary at this time to deal with the lack of pressure at Station B. BOMA's recollection is that Enbridge's evidence is that the NPS 26 line does not currently supply significant gas into the Don Valley line, so it would be able to transfer additional gas from Albion eastward, as required, while operating at lower pressure. Even if the new east-west line is built, as part of Segment B, it appears that neither it nor NPS 26 will deliver significantly greater amounts of gas than NPS 26 does now into the Don Valley line. More important, in BOMA's view, increased and more targeted DSM can reduce the need for the Segment B (see below).

It is Enbridge's evidence that all of Segment B, both the North South and the East West Sections are necessary for "flexibility" and to reduce operating risk, and to ensure that they are taking measures to reduce operating risks and enhance flexibility without impairing their ability to serve the needs of customers in the GTA's downtown core ("system reliability objectives"), that are mostly served by Station B, the so-called point of minimum pressure in the Enbridge system.

What appears to be driving the need for Segment B is Enbridge's desire to lower the SMYS ratios of two of its XHP pipelines, NPS 30, Don Valley and NPS 26, from 37 and 36, respectively, to 30 SMYS or less (to exactly what level is not clear from the evidence). Enbridge claims that if they do this, without increasing both the east-west and north-south high pressure distribution pipeline capacity in the GTA, they will not be able to maintain necessary pressure/volumes at the outlet to Station B to serve the downtown core. They also note that even if they maintain current SMYS levels for the Don Valley line and NPS 26, they will not have sufficient outlet pressure at Station B to service the core, beyond November 2015, due to additional gas required in the downtown core.

Accordingly, Enbridge proposes to loop a section of the NPS 30 (Don Valley) pipeline between the Buttonville station and Shepherd Avenue and to build a new 36" pipeline adjacent to the existing NPS 26 pipeline between the Keele and Buttonville stations.

BOMA's understanding is that the proposed reduction of pressure from over 30 SMYS to below 30 SMYS is not required by statute or by CSA Z662, including the most recent amendment to that document, FS-196-12, enacted on September 12, 2013, and made effective in March 2013. FS-196-12 (the "Amendment") amends section 4.3.4 of the underlying standard. Section 4.3.4 classifies gas transmission lines into four categories, depending on their proximity to buildings, parks, and other areas of human habitation or activity. The more densely populated when zones are classified as three or four, with four being the most densely populated areas. Classes one and two are pipe segments in rural and mostly unused locations. The regulation provides for varying distances required from these buildings and other facilities.

The recent Amendment requires, for all transmission pipelines with SMYS 30 or greater that the operator identify high consequence areas, which include all class four and class three pipe segments, and segments in class one or two locations, which are within a defined distance from defined facilities.

The Amendment goes on to require the operator to indicate in its integrity management program, how it identified high consequence areas, in addition to the class three and four locations. It further goes on to require the operator, as part of its written integrity management program to assess and prioritize the risks in each pipeline segment in a high consequence area through a risk assessment process following the guidelines in Appendix B to the Standard, and to remediate those risks using techniques set out in section 4.3.4.12 of the Amendment. While the list in 4.3.4.12 is indicative rather than exhaustive, it focuses on monitoring and evaluation measures, such as more frequent inspections, better emergency flow devices, better monitoring systems for pressure, leak detections, additional training, emergency drills, and the like.

It does not speak to reducing pressure in a pipeline to achieve a lower SMYS rating. BOMA's reading of the Amendment is that Enbridge's decision to reduce SMYS ratios in the two pipelines to 30 or below is not triggered by the Amendment.

Moreover, the difficulties that Enbridge officials discussed with the Board Chair (at T. V6, pp155-161) would not have been avoided with the implementation of GTA Project, because the additional looping proposal is from Buttonville Station down to approximately Shepherd Avenue. From Jonesville station down to Station B, which is the part of the Don Valley line that is actually in the Don Valley and is exposed to flooding, there remains a single line, and that will not change. There is still no other line to back up supply to Station B and downtown in the event there had to be a pressure reduction in order to facilitate maintenance work in mid-winter, as described by Mr. Thalassimos (T. V6, p159).

As for the reference to recent changes in the US regulation, which proposes new pressure restrictions for classes five, six and seven, these classes don't exist in Canada, and EGD offers no evidence as to what they would cover, and the degree to which those pipelines would fall outside class 4 in Ontario.

On balance, BOMA does not believe that Enbridge has made a sufficiently clear case to build Segment B for "reliability reasons".

BOMA would support the minimum build described above to ensure the required supply to the downtown core. This will also provide time to confirm efficacy of BOMA's proposed DSM approach described below and provide a ramp-up period for DSM measures. It also represents a staging of required expenditures to minimize its impact on ratepayers. Finally, the excess capacity to be created at Parkway Enbridge should allow the Parkway North pipeline and the

NPSXHP 36 Mississauga Southern Link pipeline, to move gas in a west to east direction in the GTA.

Union Applications

Parkway West

Union is proposing to establish a new Parkway West Station, including the new Enbridge Gate Station (suction) and two new compressors, Parkway C for loss of critical unit protection ("LCU") and Parkway D for "growth" (our emphasis). The Parkway D compressor is part of the EB-2013-0074 application, but it will be installed at the Parkway West station.

Union proposes to establish a new gate station for Enbridge at Parkway West (a mirror image of the existing Parkway (Enbridge) gate station), except that will have a maximum capacity of 1,600 TJs/day, the combined current contract capacity of Parkway Enbridge and Lisgar (our emphasis), upstream of the compression facilities. This new gate station would provide Enbridge with additional transportation security and an alternative delivery point to Parkway in the west end of the GTA, in the event of a catastrophic failure, resulting in the destruction of the existing Parkway Station. It will provide greater entry point diversity, one of EGD's objectives for the GTA Project. The Parkway West City Gate would connect directly to both the NPS 36, Parkway North line, and NPS 36 Mississauga South lines, as does the existing Parkway gate station. Note that a simple compressor failure at Parkway would not prevent EGD from continuing to take gas from Union at the Parkway gate station, since that gas stream is not compressed, but a catastrophic failure would shut down the entire Parkway station. The gas moving from Union-Dawn Parkway line into Parkway West, and flowing to Enbridge at the new gate station, like the gas at Parkway Enbridge gate station, would not be compressed.

BOMA is of the view that the proposal to provide Enbridge with an additional high capacity gate station makes sense, for reliability reasons, although it does nothing to reduce EGD's overall reliance on Parkway Belt delivery facilities, in other words, receiving the bulk of its gas (58% at present) at the far west end of the GTA. BOMA supports the new Enbridge gate station at Parkway West.

<u>Compressor Unit C/LCU, Compressor Unit D (growth)</u>

Union proposes to build two new compressors at the Parkway West Station, one Compressor D, which they call a "growth compressor" and a second Compressor C, which they claim is required for LCU protection. Each compressor has 44,500 hp, and is very similar to the existing 44,500 hp Parkway B compressor, so the total proposed compressor capacity at Parkway and Parkway West would be 153,500 hp, an increase of well over one hundred percent (100%) over the current Parkway capacity of 64,500 hp.

BOMA views the proposed overall increase of compression capacity at Parkway West as excessive, and not required at this time. Union has agreed that, at the hearing, one compressor can provide both some growth capacity and some LCU protection (BOMA IR and cross-examination) (T. V3, p136). One compressor is capable of performing both functions simultaneously, provided it has sufficient horsepower. Union had previously stated, in its prefiled evidence and in certain IR responses, that providing both services from the same compressor was not possible, even if the compressor had sufficient hp to do both.

With respect to the Union's proposed Unit C, to be used for LCU protection, Union's evidence is that there is no contract, regulation or policy that requires Union to construct the unit at this time (T. V2, p105). Enbridge has not requested it, rather Enbridge's evidence on the point is only that it requires "at least one" compressor at Parkway West, and that its purpose should be to compress Enbridge's increased shipments delivered by Union from Dawn to Parkway (I.A1.AE.EGD.BOMA.18). Given that Enbridge will be by far the largest user of the new compression services at Parkway West, for several years, the fact that it is not requesting or requiring two compressors at Parkway West is an indication of its relatively benign view of the risk of compressor failures, and the modest scale of market growth.

Union's evidence in the EB-2011-0210 proceeding made it clear that compression failure of the scale required to warrant LCU protection is extraordinarily rare.

In BOMA's view, there is no direct causal link between the volume of gas moving through compression at Parkway and the need for Loss of Initial Unit Protection. Gas compressed at Parkway has been increasing markedly for the last six years, and Union has not yet found it necessary to have an LCU compressor at this site now. It is not clear why Union needs it at this juncture, particularly since neither Gaz Metro, Enbridge, or the US LDCs have required it as a condition of shifting additional parts of their upstream transportation from long haul to short haul, and in the case of Enbridge switching volumes from its Parkway/Enbridge station to Parkway West, which does not require pressure, to Parkway West.

Nor has Union presented evidence that other shippers have required or even raised the issue in connection with contract renewals. It seems clear that decision of New England and Mid-Atlantic LDCs on whether to renew with TCPL (Iroquois or Niagara) and Union Dawn-Parkway/Kirkwall will be made on the basis of comparative cost and supply diversity. Their assumption will be that Union's excellent operational record will continue.

With respect to growth prospects driving the need for a growth compressor, Compressor D, Union's evidence is that it expects very modest organic growth in its CDA delivery area and northern/eastern delivery area over the next few years. It has no growth plan beyond 2015 (I.A1.UGL.BOMA.3, p9). It wishes to displace a relatively modest amount, approximately 110,000 GJs/day, of TCPL long haul capacity to its north central and eastern delivery areas with additional supplies from Dawn, which would need to be compressed, beginning in 2015. However, if Union builds its proposed Burlington-Oakville lateral, off of the Dawn Parkway pipeline upstream of Parkway West, it will displace some of the gas it currently compresses at Parkway for delivery to its CDA via TCPL, in an amount that will be a substantial offset to the 110,000 GJs/day. There are two other visible growth drivers. Gaz Metro has proposed to switch the supply for its direct purchase customers from TCPL long haul (Empress) to TCPL short haul from Parkway (beginning on November 1, 2015, assuming the Settlement Agreement is approved). This gas will be sourced at Dawn or Niagara so it will require Union compression at Parkway, and under the terms of the Settlement Agreement, it will flow into TCPL, compressed, at Parkway. As for Enbridge, if the Settlement Agreement is approved, it is permitted to, and proposes to move 200,000 GJs/day of long haul TCPL capacity to the TCPL Hamilton line to Parkway Enbridge, starting November 1, 2016, which will not require compression. While Enbridge will require compression for the 400 TJs/day of gas it proposes to source at Dawn, rather than at Empress, and for the 200 TJs/day it wishes to switch from Parkway to Parkway West, there is sufficient excess capacity with one new compressor at Parkway West to handle the 600 TJs requirement, given the current excess compressor capacity at Parkway and, given the fact that Enbridge could leave the final 200 TJs/day at Parkway or Parkway West, neither of which require compression. Enbridge's request to move the final 200 TJs/day from Parkway

Enbridge to Albion, to make a total of 800 TJs to be compressed, artificially inflates the amount of compression required, and leaves pipe empty at Parkway (see above). Enbridge provided no explanation for this.

Moreover, there are several northeastern US LDCs, both in New England and in the New York/New Jersey (mid-Atlantic) regions that BOMA expects will not recontract all of their capacity on TCPL and Union when their existing TCPL contracts expire in the 2016-18 period.

This position was also endorsed by TCPL at the hearing (T. V9, p63).

It is common knowledge in the industry that all the north-east US LDCs are reconsidering their supply options at this time, given the rapid growth of the Marcellus Shale. There are a number of proposals from US pipelines, to move additional gas from Marcellus Shale into New Jersey, New York City and New England. For example, the IHS witness confirmed that the Constitution pipeline, which is co-owned by the William Co-op and Cabit Corporation, a large US interstate pipeline and one of the largest Marcellus producers, respectively, would likely be granted a Certificate of Convenience and Necessity by FERC. The Constitution pipeline originates in North East Pennsylvania in the Marcellus Basin, and will run north and east to intersect with both the Tennessee and Iroquois pipelines between Albany and New York. A TransCanada US affiliate, the Iroquois Gas Transmission Company LP ("Iroquois"), which runs from the Canadian border near Cornwall to New York City has recently applied to the FERC for its Wright Interconnection Project, which would allow the Constitution Pipeline to intersect with both its line, and Tennessee's lines, between Albany and New York, and provide 650,000 decatherms of capacity to move Marcellus gas to New York and New England (FERC, Iroquois Gas Transmission System L.P., Docket No. CP13-502-000, Notice of Application, June 26, 2013). Marcellus producers view that project as a very efficient way to reach New York (Iroquois) and Boston (Tennessee). Another is the Tennessee Pipeline Corporation's proposed "Bullet line" which will run from Albany, New York to Boston, and would enable Marcellus gas to enter New England. Tennessee traverses the Marcellus Shale in Western Pennsylvania and has many connections into that basin. There is also a second Tennessee expansion scheduled to bring Marcellus Gas to western and central Massachusetts and Connecticut. Many LDCs in the region currently buy substantial quantities of gas in Western Canada, which they move mostly through the Dawn Parkway/Kirkwall lines, and through TCPL to Iroquois Waddington, and, to a lesser extent, Niagara/Chippewa to Tennessee (although very little gas is currently exported into New York state at either the Niagara or Chippewa export points, other than some supplies to National Fuel Gas in the Buffalo area).

BOMA believes that the LDCs will wish to maintain some supply links to the WCSB, but will move a part of that supply to Marcellus gas from Pennsylvania. This partial switch will lead to lower requirements than would otherwise be the case on the Dawn-Parkway/Kirkwall line in the next few years, beginning in 2016.

Also noteworthy is the fact that Iroquois, which transports gas from the US border at Waddington to New York City, has obtained a United States export licence, which would allow it to reverse flow and export Marcellus Shale gas into Canada, into the eastern Ontario and Quebec markets.

Union is forecasting modest growth in its eastern delivery area, other than proposed TransCanada power plant near Bath, which offsets gas already earmarked for power in Union's plans, had it been built in Oakville.

In BOMA's view, given the current substantial baseland electricity surplus in Ontario (IESO), the plans for additional renewable capacity, and the likely recontracting of many of the original gas fired NUG plants (TransAlta recently announced it has recontracted its Ottawa plant), it is unlikely that any incremental gas volumes for power will emerge in Ontario for some years, other than a gas-fired power plant which may be built in the Kitchener/Cambridge/Waterloo area. Mr. Herring's proposed growth of 6.2% per year is not documented, and is highly speculative.

As noted above, growth in Enbridge franchise is expected to be modest, with possibilities for further reductions if DSM is pursued more aggressively. DSM can also be pursued more aggressively in the Union franchise.

In summary, virtually all of the initial incremental capacity requested on the Dawn-Parkway line and incremental compression requested at Parkway West, starting on November 1, 2015, is the result of Enbridge's, Gaz Metro's, and Union's substitution of Dawn-Parkway - "short haul" upstream capacity for TCPL mainline "long-haul" capacity; it is not the result of incremental market requirement for gas. The expected <u>organic growth</u> in Union and Enbridge franchises is expected to be modest, especially if DSM efforts are enhanced, and given the growing availability of Marcellus Shale Gas from Pennsylvania, a state contiguous to New York and New England, and the threat that suppliers there pose to more distant Canadian suppliers' market share, the US LDCs' capacity requirements on Dawn-Parkway and TCPL short haul are likely to decline over the next five to ten years.

<u>Compressor D</u>

In BOMA's view, it would be imprudent for Union to construct both the growth compressor, Unit D and the LCU Compressor C at Parkway West or to provide a fourth pipeline between Brantford and Kirkwall at this time because it is not yet known whether the Settlement Agreement will be approved, and on what basis, and, therefore, whether the King's North Pipeline will be built, or whether TCPL will be enabled to build additional short haul to Union's northern and eastern delivery areas to move the 110,000 GJs/day, or whether TCPL can build alternative facilities to Enbridge's proposed transmission line. Without the certainty that additional volumes can be moved to and beyond Albion, it is not clear that a growth compressor will be required at this time.

But even if the Settlement Agreement is approved, and the new demands for compression continue from Union, Gaz Metro, and Enbridge, there would appear to be sufficient compressor hp with the addition of one 44,500 hp compressor at Parkway to secure the forecast growth and provide LCU protection. There is excess capacity in Compressors A and B for the winter 2014-2015 in the order of 170,000 GJs. The demands for incremental compression horsepower for growth are laid out at I.A1.UGL.BOMA.54(d). Union's evidence is that their compressors can perform both an operating and an LCU function (T. V3, pp 136-7, lines 1-12), assuming they have the required capacity. Union stated that the total incremental anticipated compression in the winter 2015-2016 (if the GTA Project were approved) would be 29,690 horsepower, including the addition of 600 TJs for Enbridge. That requires only one compressor, not two.

BOMA is of the view, as noted above, that the growth requirements noted above, and the LCU function can be provided at this time by the construction of one, but not two 45,000 hp compressor. BOMA concludes that if the NEB approves the Settlement Agreement as filed, BOMA would support the purchase and installation of one 44,500 compressor at this time to provide LCU protection and service new growth.

A2, A3

BOMA believes that Union's proposal to loop the Brantford-Kirkwall phase of its Dawn-Parkway transmission line raises some of the same questions as Compressor D, discussed above. Union's evidence is that it will not build the loop unless TCPL's commitment to build the King's North line is approved by the National Energy Board and Enbridge's GTA Project is approved by the OEB, or, presumably OEB approved of an equivalent TCPL build in the Parkway-Maple corridor. Union's evidence is that the TCPL King's North build is necessary to move its gas from Albion to Union's Northern Delivery Area, and move the Gaz Metro gas east to Quebec. Without such a build, those volumes would be "stranded" at Parkway or Parkway West.

BOMA agrees that the pipeline build should not commence until it is clear that there will be an agreed and NEB approved solution, amenable to all four parties to the Settlement Agreement to transport gas from Parkway to Maple, and north and east from Maple.

Do the proposed facilities meet the Board's economic tests, as outlined in the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications dated February 21, 2013, and EBO 188, as applicable?

Introduction

The Board established the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications (the "Guidelines") in EB-2012-0092, which was issued in February 2013.

EB-2012-0092 ("0092") provides, among other things:

- The economic feasibility test outlined in the EBO 134 Report of the Board, issued June 1, 1987 continues to form the basis of sound requirements on the economic feasibility test to be applied to leave to construct applications for transmission pipeline projects.

- Paragraphs one to thirteen of the Guidelines are taken, unmodified, from EBO 134.

- The Board added a fourteenth paragraph to the Guidelines:

  > "Any project brought before the Board for approval should be supported by an assessment of the potential impacts of the proposed natural gas pipelines on the existing transportation pipeline infrastructure in Ontario, including an assessment of the impacts on Ontario consumers in terms of costs, rates, reliability, and access to supplies".

- The Board wrote issue 2 in the issues list in a manner that to clearly distinguish the transmission Guidelines from the test for the expansion of distribution systems in EBO 188 (Final Report of the Board, Distribution System Expansion Reports under Board File No. EBO 188, January 30, 1998).

- The tests are different. EBO 188 requires a discounted cash flow analysis of the 25-40 year revenue stream from the customers attached in the ten years following the construction of the projects against the capital cost of the project, in the context of rolling portfolio profitability index and the test year investment portfolio. It does not take into account alleged ancillary benefits such as commodity cost savings or upstream gas transportation savings.

Issue A2

Enbridge has misapplied the Board's Transmission Guidelines and EBO 188, by doing a single economic feasibility analysis, blending elements of EBO 188 and EBO 134 for both the transmission and distribution components of the GTA Project, rather than evaluating the distribution expansion and the transmission line proposals separately, using the tests established in EBO 188 and EB-2012-0092, respectively. Enbridge applied elements of both EBO 188 and the Transmission Guidelines to all transmission and distribution assets on the grounds that both Segment A (mostly transmission, but some distribution) and Segment B (distribution) are required to realize the "associated benefits". This approach is wrong for several reasons.

First, the premise is wrong. The distribution assets of Segment A and Segment B, and perhaps even Segment B alone, without the distribution component of Segment A, are all that is required to meet the customer growth objectives in the GTA over the next ten years, even under the assumption, with which BOMA disagrees, that integrated resource planning makes zero contribution. The transmission line is not required to meet GTA growth targets. Only the distribution component of Segment A is required to realize the customer growth, and the alleged gas transportation savings for Enbridge's ratepayers. The transmission pipeline is not. Second, even if both transmission and distribution investments were required to realize <u>all</u> the benefits, the analyses of each should be done separately, since as noted above, the tests are very different and the results would be very different from the results obtained by the "blended analysis". For example, it is doubtful that the distribution expansion project, taken on its own, would have a present value of greater than one, especially when the necessary service lines were included, although the investment portfolio for the year 2014 might provide some support if there were other projects with high paybacks.

The correct approach is for Enbridge to assess the economic feasibility of the distribution investment (Segment B plus the distribution component (40%) of Segment A) against the customer revenues that would result following the EBO 188 methodology.

Enbridge has not done this, so we do not have the profitability index for the distribution expansion only. However, Enbridge's evidence is that under its "blended analysis" of the entire GTA project, including both transmission and distribution assets, the present value of the pre-tax revenue stream generated by the project is $2,026.6 million, of which 57.3% is from transportation savings (lower upstream transportation tolls offset by higher commodity costs), 32.3% is from distribution customer revenues (our emphasis), and 10.4% attributable to the transmission tolls collected from shippers on the transmission line under the proposed rate 332 (Ex E, T1, Sch 1, p 4 of 9, updated 2013-07-22). From these numbers, it seems that an EBO 188 analysis of the proposed distribution investment would result in pv of less than one, but without the distribution facilities investment number broken out, or it is hard to be certain. But it is likely to be less than one, given the relatively large amount of distribution assets, when you include the services in Segment B, and the distribution component (40%) of Segment A.

Had Enbridge made a separate analysis of the distribution investment (all of Segment B plus the distribution component of Segment A), and assuming its customer and volume forecasts were accurate, and there was no change in the nature of its DSM program, the present value of the project's revenue stream would be reduced by two-thirds (both the upstream transportation savings and 332 transmission revenue would be eliminated), the utility's cost of capital would have been the same, and the capital investment would have decreased by the amount of the transmission component. With respect to the potential alternatives, the cost of a distribution only pipe from Parkway to Albion (one option), is not provided in the evidence, as such a line was not set out as an option. Given this result, the onus on the Company to show that all of Segment B must, nonetheless, be built now for reliability reasons is very high. The reliability issue is discussed above. The Board will recall that Enbridge stated, in response to APPrO (see above), it could meet its ten year growth requirement by building only the north-south portion of Segment B.

On the other hand, the proposed transmission line should be evaluated using the Board's EB-2012-0092 Filing Guidelines, which is effectively the EBO 134 criteria plus one important additional criteria. The transmission line investment would not result in any additional customer revenue stream, as those revenues have already been counted in computing the NPV for the Distribution Investment. So the transmission line would fail the first leg of the three legged test for new transmission. The revenue from transmission shippers would not be enough to sustain a pv of anywhere near one. Therefore, the DCF analysis in the Transmission Guidelines would not justify the build.

However, for the second leg of the test, Enbridge <u>could</u> claim some demonstrable upstream transportation savings as "revenues" attributable to the transmission line, subject to the caveats that those same upstream transportation savings would have also been obtained, had Enbridge built a distribution connection to Albion only, and TCPL built the required transmission facilities. In evaluating the second stage analysis, the cost against other <u>quantifiable factors</u> (our emphasis), the Board should insist that the measurement of landed gas cost savings reflect reasonable price and toll assumptions, and take a very conservative approach, given the historical volatility of these prices and the uncertainty inherent in any forecast. The alleged savings from net transportation costs are based on tolls and commodity price projections over a ten year period that are highly speculative. Whether the transmission line is viable depends on the DCF analysis of those savings (revenues) plus the rate 332 revenue stream when set against the capital cost of the project results in an NPV of one or more, unless there are such additional unquantifiable but pertinent public interest considerations that would increase the overall attractiveness of the investment (the "third step" in the 134 analysis).

As the Board is well aware, the case for the economic viability of both the Enbridge's GTA transmission line, or the entire GTA project, if one accepts EGD's "blended approach" to economic feasibility and BOMA does not, and the viability of Union's projects and long term contracts, hinge on the alleged upstream transportation cost savings net of gas commodity price increases which result from Union and Enbridge reducing their contracted long haul TCPL capacity, and increasing their TCPL short haul capacity. The utilities claim that this strategy will result in a lower delivered cost of gas than exists currently, even allowing for the higher gas prices at Dawn than at AECO/Empress. For simplicity, the LDCs analysis has used the Dawn gas purchase price and used Dawn to Parkway, an analysis of other pertinent pipeline tolls, and short haul TCPL transportation costs, and compared those with the AECO price plus TCPL long haul tolls. To repeat, EGD's evidence is that, as noted above, using their blended analysis of the transmission and distribution components of the GTA project combined (which method APPrO believes to be incorrect) 57.3% of the cash flow is from forecasted upstream transportation savings, 32.3% is from revenue for new customers, and 10.4% revenue from Rate 332 shippers. If the net operating cash flow is calculated for transmission line alone, the percentage of cash flow attributed to upstream transportation savings would be approximately 90% of the total (EB-2012-0451, Ex E, T1, Sch 1, p4).

In BOMA's view, the costs and benefits in their DCF calculation of upstream transportation cost and benefits are not equivalent. Enbridge and Union are comparing apples and oranges in their comparison of the costs of building their proposed infrastructure with the alleged upstream gas transportation benefits, net of higher commodity costs paid at Dawn compared with AECO, given the <u>nature</u> of the alleged costs and benefits (our emphasis).

The proposed costs of the pipelines and compressor and related equipment, while subject to a recent modest adjustments, are now reasonably firm, and should not exceed nor be less than Union's and Enbridge's most recent estimates by very large amounts, say nothing larger than about ten percent.

On the other hand, the alleged benefits which depend on future levels of (a) various North American upstream pipeline transportation tolls, including those of TransCanada, and (b) even more so, the future price of gas at various hubs in North America, notably AECO in Alberta (the second busiest trading centre in North America), and Dawn, the most active Ontario trading centre, which prices, particularly the future price of gas, are much more speculative, particularly when they are forecast for periods of as long as ten years.

As the Board well knows, pipeline tolls themselves have been somewhat volatile in Canada and the United States in the last few years. For example, TCPL long haul tolls from Empress to the (Enbridge) Eastern Delivery Area increased by more than 100% in the last few years. In the RH-003-2011 case, TCPL estimated the 2013 Empress to Dawn toll, absent its restructuring proposal, at $2.74/GJ; its restructuring proposal reduced the toll to $1.47/GJ. The Board approved a fixed five year toll from Empress to Dawn, effective July 1, 2013 of $1.42/GJ ("compliance toll"). However, if the Settlement Agreement is approved, that toll will increase by 19% to approximately $1.60/GJ. There are also complexity and transparency issues surrounding the utilities' calculation of US pipeline tolls, on which virtually no evidence has been provided.

On the other hand, it is reasonably certain that all the short haul tolls established in RH-003-2011 will increase by 155% if the Settlement Agreement is approved. The Board will recall the LDCs' initial position, on the execution of the Settlement Term Sheet, that tolls would increase "proportionately" under the Settlement Term Sheet and, therefore, their calculation of the financial benefits for moving from long haul to short haul would not be affected by the Term Sheet. Now we see short haul tolls are proposed to increase at a rate by 250% of the rate of increase in long haul tolls. Pipeline tolls, in particular those of TCPL, have not been stable in recent years, and given the uncertainties faced by the mainline in the next few years, including the Oil East initiative, the mid-term adjustment under the Settlement Agreement (subsection 13.2(b)), and the uncertainty around what the NEB will decide about the Settlement Agreement, they may be even more volatile. They are, however, likely to gradually reduce, given the growing number of new pipeline projects under construction across North America. Moreover, the parties and the Board have no assurances that the toll numbers for long haul and short haul are realistic until TCPL provides details on how the tolls were derived, until the NEB makes its decision on the proposed Settlement Agreement, which will not take place until the second quarter of 2014. Gas commodity prices have been much more volatile than transportation tolls, and have fluctuated over a wider range of prices more quickly than any other exchange traded commodity.

It is virtually impossible to forecast gas prices with any accuracy over a ten year period, or the relationship between AECO and Dawn prices and other basis differentials in North America over ten years, even assuming the use of the most reliable and transparent published indices of trading hub prices and gas futures, such as the NYMEX strip. The fact that Enbridge used a little known private forecasting firm, which used "proprietary software" to make forecasts of gas prices, and did not disclose the basis of the forecasts using that method is unacceptable. Enbridge's proposed 51 cent average differential over the next twenty years between the Dawn and AECO prices is preposterous, and is much lower than any public index. Union has used 92 cents, and TCPL filed daily prices data for the last ten years, which showing a range of 50 cents to $1.75. More recently, the difference between Dawn and Empress have gone as high as $1.50/GJ (Dawn higher than Empress). In 2005, the differential was $1.76/GJ in 2010, $0.84 cents (RH-003-2011, p211). At a $1.50 differential, the net savings claimed by Enbridge virtually disappear and Union's turn negative (EB-2012-0451, J4.10).

If the Board is going to use any numbers at all, and BOMA would prefer that it not try to forecast gas cost savings, it should use a series of different scenarios, given the intrinsic difficulty of making any prediction of these variables, it should adopt a very conservative approach, and hold the utilities responsible for any shortfall from the forecast differential.

The calculations of net upstream transportation savings and gas commodity savings is a very different exercise than the calculation required by EBO 188 for distribution expansion where forecast from new customer connections for each type of customer, on which to base load forecasts, which support a revenue forecast over an appropriate number of years, which is compared against the capital cost of the distribution infrastructure to determine Net Present Value. While there is some risk of not achieving the proposed connections and volumes, that risk is <u>orders of magnitude less</u> than the risk associated with gas commodity costs (our emphasis).

Moreover, the intervenors and the Board have no assurance that the toll numbers for long haul and short hall tolls are reasonable until the TCPL provides details on how the tolls were derived, until the NEB makes its decision on the proposed Settlement Agreement, or at the earliest, when TCPL files the Settlement Agreement with the NEB and explains in the submission how it arrived at the numbers. TCPL and the LDCs have, so far, refused to provide the information required to assess the tolls, despite BOMA's repeated requests to do so, and TCPL's commitment in the September 13th Technical Conference to provide such information. So intervenors have no background detail which shows how the tolls the LDCs provided in the Settlement Agreement were calculated. For example, there is:

- no detail on the assumptions used to derive the Mainline Cost of Service (Settlement Agreement, Appendix A) for the period 2015 to 2020, especially the assumptions which underlie the EOT's forecast cost of service over the six year period, despite the fact that TCPL and the LDCs claim that sixty percent of the toll increase for the 2015-2020 period was necessary to put the EOT on a sustainable cost of service basis going forward. For example, which capital expenditures, which builds did they indicate, which turnback of capacity of existing shippers, in which categories did they factor in, how did they deal with amortization of the LTAA over the period, and what were the amounts in the LTAA in each year, and why these amounts were deemed appropriate and fair;

- no explanation of how TCPL throughputs were calculated over the same period, with reference to the throughput forecast in RH-003-2011, and any amendments TCPL has made, and why, no estimate of likely decontracting by shippers, and no indication of where incremental volumes would come from, in each of the EOT, NOL, and Prairies line, notwithstanding the fact that TCPL had already prepared throughput forecasts to 2017, for RH-003-2011;

- no explanation of how the Bridging Amounts were determined on an annual basis and how they were factored into the tolls calculations. The tolls were set high enough to support both the restoration of the EOT cost of service and the agreed bridging contributions to offset the mainline deficiency, but how were the objectives, time frames, and actual amounts arrived at?

No examples of the derivation of illustrative long haul and short haul tolls from first principles, as was requested by BOMA. The LDCs' and TCPL's view was that the information would be provided to the NEB as part of TCPL's application, but that is not what was promised by TCPL at the Technical Conference. BOMA is not sure how the Board is to judge the sustainability and fairness of the tolls in the Settlement Agreement without more information on how they were arrived at. The companies should have provided the mathematical derivation of the tolls.

Union has made much of the fact that the proposed Compressors C and D, if built, would be paid for mainly by M12 shippers, while most in-franchise customers would pay a bit less, through a decline in allocated administrative costs. However, Enbridge accounts for approximately two-thirds of Union's total M12 volumes, so that Enbridge ratepayers will end up paying for much of Union's proposed Parkway West infrastructure. The proposed increase in M12 rates is substantial, something in the order of eight percent.

<u>A4 - DSM Alternatives</u>

With respect to the idea that DSM is an alternative to adding more facilities to Enbridge’s gas distribution system, two significant matters came to light during this proceeding that clearly demonstrate that Enbridge may only view DSM as cash cow, whereby it can invest rate payers’ dollars and earn shareholder incentives.

1. Enbridge system planners design the system using peak hour demand on a design day while Enbridge DSM planners only consider annual demand.

2. Enbridge system planners summarily dismissed using DSM as an alternative in a planning team meeting while not one DSM planner was in the room. Reference: Transcript Volume 7, September 27, 2013, page. MR. BRETT: Was anybody from the DSM group at those meetings on a continued basis or regular basis? MR. FERNANDES: No, they were not.)

To put these two conflicts in perspective, one need only revisit EBO-169-III which established the original framework for natural gas DSM in Ontario and wonder how Enbridge could stray so far from the original impetus for DSM. The Board stated, at page 1 of its Decision:

> "During November and December of 1992, the Ontario Energy Board ("the Board") held an oral hearing on the generic issues involved in the demand-side management ("DSM") aspects of integrated resource planning ("IRP"). After evaluating the evidence and arguments submitted by the parties, the Board endorsed the need for formalized DSM planning by each of the three major gas utilities in Ontario, and concluded that these companies should implement their DSM plans as soon as possible. The Board's Report is attached." (Reference EBO 169-III page 1).

Clearly the intent of the Board was to ensure that DSM was considered as an alternative to adding more distribution facilities. Furthermore, that report established the planning parameters Reference EBO-169-III page 14):

> *Avoided costs should be time-differentiated (e.g. annual, seasonal, monthly and/or daily; peak day) and system differentiated. A **“single value” avoided cost approach is not considered adequate**.*

Hindsight may be 20/20, but had the Board continued with its plan to require Ontario’s natural gas utilities to do integrated resource planning, perhaps a more robust approach to DSM would have drastically altered the required investment in new facilities, reducing the cost of gas distribution in Ontario. In a report on gas integrated resource planning (IRP) prepared for the

Board, dated September 16, 1991, (Reference Report on Gas Integrated Resource Planning, September 16, 1991, page 9) the following definition of IRP was put forward.

> *Integrated resource planning (IRP) for natural gas utilities is an expanded method of planning whereby the expected demand for natural gas services is met from the least costly mix of supply additions, energy conservation, energy-efficiency improvements and load management techniques (i.e., the integration of supply-side resources and demand-side resources). Some of the specific objectives of the planning process are to continue to provide reliable service, equity among ratepayers, and a reasonable return on investment for the utility while addressing environmental issues and achieving the lowest cost to the utility and the consumer. The methodology for calculating the "cost" of each option and the analytical framework used for insuring consistent treatment of both supply-side and demand-side options must be developed and adopted prior to the development of actual plans.*

These same documents suggested that environmental externalities be included in the analysis (Reference EBO-169-III page 150). This was done at the outset for the first few DSM plans of the natural gas distributors, but was later dropped notwithstanding Ms. Ramsay's recollection (Reference: Transcript Volume 7, September 27, page 11):

> *MS. RAMSAY:* No, external environmental benefits were never included. They were considered early on in EBO-169 and there was a major study in terms of trying to quantify what those external environmental benefits would be, but in the end the Board decided on using the TRC test, not the societal cost test, and environmental externalities have never been included in our calculations.

We also learned in this proceeding that Enbridge does not even include the avoided costs of its capital investments, the very costs that were key to the original framework in EBO-169-III. (Reference Transcript Volume 5, September 24, page 115):

> *Ms. RAMSAY: Yes, we can confirm that that is the case. And when we looked into it, it's our recollection that we removed the distribution component of the avoided costs about the same time that the company was moving towards a performance incentive that was based on TRC results. And it was deemed at that time that it wouldn't be fair for the company to be receiving a return on investment for the capital infrastructure and receiving a performance incentive based on deferring that same capital infrastructure. So it was removed.*

MR. POCH: You're aware that the Board's DSM Guidelines in section 6.2 specifically call for avoided costs based on, quote "... long-term estimates, and include avoided supply-side costs such as capital, operating and commodity costs."

In questions to the combined Environmental Defense- Green Energy Coalition panel of experts, the Panel Chair asked the "what if" question (Reference Transcript Volume 7, September 27, page 106):

MS. CHAPLIN: Would I be correct in saying that sort of the cumulative message of your evidence is that if Enbridge had undertaken sort of formalized integrated resource planning, it would be able to achieve the objectives it's seeking to achieve through DSM measures rather than supply-side measures? Is that a fair characterization?

Mr. Chernick's response hit the nail on the head (Reference Transcript Volume 7, September 27, page 107-8):

MR. CHERNICK: I would start by saying I'm not sure how important formalized is. Formalizing the IRP process is important if the utility isn't paying attention and somebody needs to basically make them sit down and do their homework. And that actually could be internally within the company, that top management could say: All these different parts of the company need to talk to one another and turn out a comprehensive analysis that we can follow and we can file with the Board. Or it could come from -- the direction could come from the Board. But the important thing is that you not break, or the company not break these issues into ***separate islands that don't communicate with one another****. And it looks like the company has taking the position that: Well, we'll just wait on the pressure issue at station B until it's time to get approval to start digging, to build some looping on the Don Valley Parkway. And had they brought that issue to the DSM people and started a targeted program. I think the other witnesses will have a very strong opinion that they could have kept down the loads on that line considerably and avoided any need for expanding the Don Valley Parkway, without scrambling in any way to do it. That also would have given them more flexibility in terms of reducing pressures on the lines, to the extent that that is something that is important and that they want to do it. It wouldn't necessarily deal with the issue of importing additional gas from the United States and bringing it in through Parkway.*

It is clear that Enbridge keeps its system planners and its DSM planners apart in more ways than one (Reference: Transcript Volume 5, September 25, page 4):

MS. OLIVER-GLASFORD: Our DSM framework provides a broad-based annual savings. That's how it's measured and tracked. Currently there is no verified relationship between DSM efforts and peak load reductions. In fact, it's quite different *than the electric side, where they have the data enabling in the programs that do target peak load reduction in the form of demand response and the like.*

This lack of data was summarily dismissed by two expert witnesses (Reference: Transcript Volume 7, September 27, page 96 -7):

MR. STOLL: Would you have any reason to disagree when Enbridge says it does not have the same customer data that would be produced by smart meters for the electricity utilities?

MR. JARVIS: Perhaps I could help with that. Enbridge is doing a great job of rolling out, for larger customers, all kinds of meters and that's --

MR. STOLL: For larger customers, not for residential.

MR. JARVIS: We recommend that they mine that data as well as they can. It's remarkably helpful.

MR. CHERNICK: I would also assume that, for cost allocation purposes, the company would have at least a sample of hourly meters on the various customer classes, so that they could characterize their load shapes but I haven't checked that out. Nobody asked me that.

However, the real question is not what could have been done, but what should be done on a going forward basis. And how can the Board ensure that its guidelines are followed?

BOMA has argued in the past that DSM should be based on real data, rather than engineering estimates. Mr Jarvis has set the standard for basing DSM on real data. And he has provided a roadmap for program design in his response to Board Staff Interrogatory 3. (Reference: Transcript Volume 7, September 27, page 65-6):

MR. ELSON: It was also stated that your forecast numbers are more of a technical potential and are not practically achievable. Could you respond to that as well?

MR. JARVIS: Yes, we saw that comment, and I guess it surprised us a little bit. We completely understand and respect the history of DSM in Ontario and across North America, in terms of, when there weren't large data sets available to base projections and forecasts and business cases on, it made perfect sense to use engineering calculations, and it served the province well, and it's got us to this point.

The idea of it somehow moving to real empirical data, where you can look at the actual performance of buildings and make adjustments for material differences and then identify the savings that way, as opposed to projecting engineering calculations, we've always seen it, and I guess the folks that we talked to have always seen that this is moving us to a higher level of accuracy, a high level of dependability, and it also provides a management focus. In other words, every building now has a potential gas savings attached to it that can be presented to the owner, which can be used on an ongoing management basis.

So we were surprised to feel -- or to hear the thought maybe this whole movement towards data and benchmarking that's got illustrated by, again, Energy Star in Canada and Green Energy Act, this move towards data-, evidence-based projection of savings potential and targeting for individual buildings would be less rigorous. I believe this is far more rigorous and by far the most accurate way of moving forward.

In Enbridge's argument in chief, the characterization of Mr. Jarvis's roadmap is not consistent with the evidence (Page 26.)

The suggestion that there could be a complete overhaul of the DSM approach for gas distributors in Ontario is speculative and out of step with considerations of cost-effectiveness, and, in any event, does not represent a realistic alternative to meeting the needs of Enbridge's distribution system within the time-frame required for the GTA Project.

Mr. Jarvis outlined the program approach in a response to Board Staff Interrogatory #3 and it is not inconsistent with the new programs that Enbridge is beginning to pursue (Reference Transcript Volume 7 page 94):

MR. JARVIS: If the question is directed towards the lead file for a DSM program for this particular proceeding, which I assume it is, I think the good news here is this is not a change of direction that's being proposed here for Enbridge.

The company has had the foresight to already have in place the -- to Run it Right, they're hiring the kinds of people that we're referring to already.

So this is more of reinforcement and a focus of what they are already doing. There's not a change of direction.

Similarly the suggestion in Argument-in- Chief that Mr. Jarvis' program approach is not cost effectives is also inconsistent with the evidence (Reference: L.EGD.ED.1):

> *Measures to improve efficiency in high gas intensity buildings go beyond those included in Marbek's DSM Potential Study and are typically site-specific equipment repairs, upgraded control of buildings systems, and testing, tuning and rebalancing of heating plant and systems. Such projects show generally good Total Resource Cost ("TRC") test values, can be implemented quite quickly, and serve to improve building performance as well as energy efficiency. They require a systematic approach to identify target buildings, engage owners, isolate the inefficiencies, implement the necessary improvements and verify the results.*

BOMA suggests that the Board ensure the following:

- DSM be considered an alternative to supply facilities with integration of supply planning and DSM planning
- The peak impacts of DSM be included in all planning
- Estimates of DSM potential be based on empirical data, not engineering estimates
- Measurement and verification of results be based on empirical data not engineering estimates
- Targeted DSM is used to address local constraints.
- Avoided costs for local transmission and distribution are included in cost effectiveness analyses for DSM.
- Environmental externalities are included in cost effectiveness analyses for DSM.

BOMA is of the view that DSM measures, if implemented promptly in 2013, 2014, and over the next ten years, could contribute all or part of the required peak day supply (and remainder of the year supply) in the downtown core by reducing the peak day consumption of many of the existing and proposed commercial buildings in the downtown core. This conclusion is based on Enerlife's conclusions to the effect that:

> "all load growth in the GTA area can be completely offset through commercial and apartment DSM and that overall demand can be significantly *reduced* with the addition of residential and industrial DSM." (Ex. L EGD.ED.12, p1 of 2 (Executive Summary))

Enerlife further concludes that:

> "Working with other parties, Enbridge can readily identify and target the largest gas savings potential customers in each sector, and support them in understanding and achieving the considerable energy and cost savings potential in their buildings". (Ibid, p2)

Based on these conclusions, BOMA believes that the Board, in addition to the above directives, should direct Enbridge to launch a performance based DSM program, using integrated resource planning framework, directed at the major commercial and apartment buildings of the downtown Toronto core, in particular, that part of it which is served off Station B, with a ten year term, which would focus on reducing peak demand in these buildings as quickly as possible.

<u>A5 - Timing</u>

Enbridge will have, as noted above, a number of options, which could be used in isolation or more likely as part of a package of measures, to deal with maintaining the required pressure at Station B for the winter of 2015-16 and beyond, including:

- construction of the north-south part of Segment B;
- to pursue more aggressive and targeted DSM measures, along the lines recommended in the Enerlife Report, and in this submission;
- negotiation of access to the gas supply which TCPL/OPG transports to their plant, for a number of days in the winter. There is now, and will be for the next few years, a considerable surplus of electricity in Ontario. These conditions should permit the parties and the OPA to reach agreement on this matter.

- Enbridge could accelerate the pre-engineering work, at least the North-South portion of Segment B, so as to be in a position to complete construction by November 1, 2015.

Union Project Economics

The total estimated cost for the Brantford/Kirkwall project is $204 million - $96 million for the pipeline, and $108 million for the Parkway D compressor. The updated cost for Parkway West is $219 million (EB-2012-0433, p 100 of 121 Updated). The updated total cost of the two transmission projects is $425 million.

Both Parkway West and Brantford/Kirkwall/Compressor B are transmission projects. While they are separate applications (one was ready to submit before the other), they should be combined for the purpose of the economic analysis. In fact, the two applications are a single project, in that:

- they are both driven by the same contingencies, namely growth in demand for Union's Dawn-Parkway service; in other words, the growth in demand, which makes the Brantford-Kirkwall pipeline loop and Compressor D desirable also underpins Union's case for the Compressor C, the LCU compression, namely, the fact that beginning in 2015-16, the Parkway compression facilities will be at capacity, on peak day and other cold winter days, and will continue that way for several years;

- both projects are dependent on the Union export market, especially exports to Enbridge. For example, Parkway West creates, among other things, an important new gate station for Enbridge;

- both compressors will share common facilities at Parkway West; and

- all of Parkway West infrastructure is dedicated to serving Compressor C and Compressor D, and the new Enbridge gate station.

BOMA is of the view that the correct method of analysis is to combine the capital costs of Parkway West, including Compressor D and the Brantford/Kirkwall line loop.

Union did not do a DCF calculation on this basis.

But applying the discounted cash flow to Phase I of the 134 test to the combined Parkway West and Dawn Kirkwall expenditures, based on using the combined capital cost of approximately $420 million and revenue for the same (the M12 contracts), it is clear that the Phase I DCF would be below one. It would not even be close to one.

Turning to the Phase II test benefits, if the Brantford/Kirkwall/Compressor D/DCF resulted with annual gas savings valued at $18.5 million (original estimate) yielded a pv of 1.47, and assuming it is reduced to approximately 1.22 to reflect the updated savings of $15.4 million (Updated November 7, 2013 J4.5, J4.6, and J9.2), and assuming an approximate doubling of the capital cost (to include Parkway West), and no additional savings from Parkway West, the Phase II DCF would be about half of 1.22 or .61, well below the threshold for 1.34. It would fail the second branch of the test. There would appear to be no other public interest benefits to add in the third leg.

In BOMA's view, the applicant must show a compelling case as to show why a project should proceed on the basis of some other qualitative public interest consideration in the face of a failure to meet the first and second tests of the new Transmission Guidelines by such a large amount.

The other considerations mentioned by Union include:

- greater reliability of gas supply which BOMA does not agree is correct (see above);

- the fact that the LCU unit is required at this time, along with a growth compressor (BOMA believes only one compressor is necessary, and that one only once the path ahead to Enbridge and/or TCPL implementing their proposed investments is clarified by an NEB decision on the Settlement Agreement), which TCPL and the three LDCs accept;

- a second gateway to Enbridge, which BOMA endorses, but it is a relatively small part of Parkway West, as Enbridge will lease part of the site and build the gateway infrastructure;

- the fact that Union wants guaranteed recovery in rates for these transmission projects should give the Board further pause as to viability of the projects;

- Enbridge's, the largest user of Dawn-Parkway, evidence is that it requires one compressor at Parkway West.

Given all of the above, at this time, BOMA would support only the Parkway West land acquisition, connected to Dawn Parkway, and the facilities necessary to establish a second Enbridge (suction) gateway, as proposed.

Enbridge Transmission Rate 332, Issue D5

BOMA is of the view that the allocation of risk between the shareholders and ratepayers implicit in rate 332 is inappropriate. First, after stating that it will treat the Albion line as a "stand-alone cost item", as noted above, EGD states that "in the event there are no shippers for the transportation service, distribution ratepayers will be allocated the entire revenue requirement"

(Ex E, T1, Sch 2, p2). That is a grotesque misallocation of risk, particularly in light of EGD's apparent determination to proceed immediately with construction (see above) and is unacceptable. If there are some shippers on the line, Enbridge proposes a range rate (332) under which shippers will pay a toll inversely proportional to the amount of total capacity that is utilized. The lowest rate will apply when all 1,200 GJs/day of transmission capacity is utilized by shippers. However, the maximum rate is set based on 538 TJ/day of utilized capacity, which, as it happens, is the amount requested by Union, Gaz Metro, and Enbridge (170 TJ/day). But if the demand is lower than 538 TJ/day, because of some unforeseen difficulty with either the Gaz Metro, Union and EGD volumes, which have, given the Settlement Agreement, not yet been allocated to them, let alone reflected in precedent agreements and contracts, then EGD's ratepayers would remain responsible, as they would in the "no shipper" case above. BOMA urges the Board to find that any shortfall between the revenues required to pay the revenue requirement for the Albion Transmission Pipeline (EB-2012-0451, E1, T1, Sch 2, Attachment 1) and revenues, actually collected, should be recovered from the shareholders, not ratepayers.

<u>Issue C6</u>

Should pre-approval of the cost consequences of the two long term transportation contracts be granted?

As part of its EB-2013-0074 application, Union has applied under section 36 of the Ontario Energy Board Act for pre-approval of two long term short haul contracts on the TransCanada Pipelines Limited ("TCPL") mainline.

In May 2012, Union entered into a TCPL open season for two new short haul firm TCPL transportation contracts from Union Parkway Belt to the Union Northern Delivery Area, and to the Union Eastern Delivery Area. The combined volume is 110,000 GJ/day, beginning November 1, 2015. The new contracts are meant to replace an equivalent amount of Union's long haul capacity with TCPL to its Northern and Eastern Delivery Areas (100,000 GJ to Eastern Delivery Area, 10,000 GJ/day to Northern Delivery Area). The switch from long haul to short haul delivery is forecast to achieve savings for Union's customers of $15.4 million/year (J4.5 Update, November 7, 2013, pp1-2).

The issue is whether these proposed contracts meet the criteria in EB-2008-0280, the Board's Draft Filing Guidelines, for the Pre-Approval of Long Term Natural Gas Supply and/or Upstream Transportation Contracts.

In its letter of February 11, 2009, which accompanied the release of the Guidelines, the Board noted that upstream pipelines sometimes require long term shipping contracts to support new infrastructure investments, and is therefore, in some cases, long term LDC transportation contracts may be justified.

However, the examples used in the Board's covering letter referred to "Greenfield" pipelines built to serve new supply areas, eg. frontier gas, or new types of infrastructure, such as LNG liquefaction terminals. The pipelines loops or compression that will be constructed by TCPL in this case is different. First, it is a simple pipeline capacity expansion, to make the additional short haul capacity available. These are routine pipeline expansions for which TCPL has historically required ten to fifteen year contracts. They are part of the ordinary course of business for both TCPL and the LDCs. The additional gas supply will come from Dawn.

In this respect, the proposed contracts are much like Union's Niagara to Kirkwall contract, for 21,101 GJs/day for ten years, the cost consequences of which Union sought pre-approval two years ago (EB-2010-0300/0333). The Board refused to grant approval in that case.

In turning down the application, the Board noted that:

> "It is the Board's view that its process for the pre-approval of the cost consequences of long term transportation or supply contracts was intended to serve a very specific role in the development of natural gas infrastructure, in the interests of Ontario consumers. Adoption of the process was recognized by the Board that as a matter of commercial reality, the developers of natural gas infrastructure might in some circumstances require long term commitments to support large infrastructure investments".

This is not one of those extraordinary cases. Given TransCanada's size and annual builds, this is not large infrastructure; nor is Union's commitment particularly large, given Union's size. Moreover, it is not clear from the evidence exactly what infrastructure, if any, TCPL proposes to construct to support Union's switch from long haul to short haul.

Moreover, the Settlement Agreement provides that TCPL's long and short haul tolls will be fixed, for the next five years, at levels which are set out in the Agreement, and that future short haul tolls, post-December 31, 2020 for the EOT paths will be established based on the EOT's revenue requirement (a cost of service basis). All of this should provide some comfort to Union.

Finally, the contract, in this instance, does not provide access to a new source of gas supply. The Board noted in 2010, in the case referred to above, that Marcellus gas was not new, it was already being produced and having an impact on the market, nor could it be properly described as a frontier area (Ibid, p9). That is even more the case today, and the basins sourced by Union at Dawn are even more established. All that is happening here is that Union is replacing gas from one established basin, with gas from other established basins. As an aside, Union's interest in Marcellus is not large, unless Marcellus gas can be shipped through Dawn; it is more interested in basins which transport to Canada via Dawn.

What the Board concluded in EB-2010-0300/0333 is much more applicable in this instance, to wit:

> "As noted earlier, the purpose of the pre-approval process, is to support the development of new transportation facilities to access new natural gas supply sources. This is clearly not the case".

BOMA suggests that Union get approval for the cost consequences of the proposed contracts in the normal way, through its next rates case (prudency review).

Issue B5 - Guaranteed Cost Recovery of Union Projects

Preapproval of the Recovery of the Cost Consequences of the Projects in Rates

Union has also asked for pre-approval of the cost consequences of its Parkway West Project and its Brantford to Kirkwall expansion/Compressor D project, pursuant to section 36 of the Act and their inclusion in rates starting in 2015. The fact that Union has asked for, in effect, a guaranteed recovery of the cost consequences of the project in rates commencing on November 1, 2015 means that the Board should set an especially high bar for these projects obtaining leave to construct. That is because, at least in Union's view, would mean the prudence review needs to be done as part of the Leave to Construct proceeding, that is, in this proceeding. This should lead the Board to adopt a very conservative approach when assessing these applications.

First, as noted elsewhere in these submissions, in BOMA's view, until the overall regulatory framework is clarified as a result of the NEB approval of the Settlement Agreement or the TCPL and the LDCs acceptance of any NEB amendment to it, the Board should not approve either the

GTA project (other than the north-south part of Segment B), the Brantford-Kirkwall pipeline project, including Compressor D, or the Parkway West project.

Moreover, it would not be prudent to proceed with their investments at this time, in the absence of assurance that TCPL will build the needed transmission infrastructure in the EOT and that the tolls and related matters will be reasonable. If, for example, the NEB turns down all or a significant piece of the Settlement Agreement, the parties may not be able to agree on whether to accept it. If all cannot agree on the NEB alternative, then there is no Agreement. In the event the bottleneck east of Parkway will not be alleviated, that the additional volumes will not flow through Parkway and therefore the new Union compressor may not be required. This Board requires some clarity from the NEB before it acts. Nor are all the parties yet at the table. Recall that this is a comprehensive document. Its preamble includes, among other clauses, the following final clause:

> "Whereas the Parties wish to enter into an Agreement to resolve matters related to, among other things, the efficient development of natural gas infrastructure in Canada, specifically in the Provinces of Ontario and Quebec, in accordance with the terms and conditions set out herein."

Third, the Board should not grant preapproval of the cost consequences in this case, in any event, as it is not possible to do a prudency test in advance of expenditures being made. The prudency test must be applied after the results of the expenditures are known, even though the test applies to what the utility knew or ought to have known at the time it made the decision(s). Without having the ability to do a proper prudency review, the Board is handing Union a single cheque for an indefinite amount.

Fourth, there is no precedent for granting the requested approval at the same time as the leave to construct is granted.

Fifth and finally, Union's evidence, that it would not build the facilities if it did not receive such approval is not credible, and is inconsistent with the regulatory compact under which it operates in Ontario. If facilities are required to service Union's customers, and if the facilities are economic on the basis of the Board's approved tests, then Union has an obligation to build. It can expect, in the normal course, to be allowed to place the cost of the assets it builds in rate base, assuming they are used or useful, and assuming they were prudently incurred, but it must build.

Summary of Recommendations

BOMA respectfully recommends that the Board:

1. approve the recommendation in the DSM Alternative section of these submissions.

2. decline to grant Enbridge leave to construct its 42" Albion transmission line, its 42" distribution line, the east-west part of Segment B, pending NEB's approval of the Settlement Agreement on TCPL's and the eastern LDCs' agreement to accept an NEB decision to create a New and Approved Settlement Agreement.

3. direct Enbridge to request TCPL to construct a transmission line from Bram West to Albion and the King's North line or an alternative transmission line to Albion, the latter as agreed in the Settlement Agreement, and to collaborate with TCPL on route selection and all other pertinent matters, once the NEB has approved the Settlement Agreement, or the parties have accepted a revised Agreement.

4. to grant Enbridge leave to construct the Parkway West Gate Station and connections to the NPS 36 Parkway North and NPS 36 Mississauga South lines, and related facilities.

5. if the Board does not wish to decline leave to construct the transmission line, grant leave to construct the transmission line only on condition that:

   (a) the Enbridge shareholders be responsible for any part of the line that is not used or useful, for the financial consequences of any underutilization of the line, and that only that part of line under firm contract to shippers be deemed used or useful;

   (b) the transmission line commence at Bram West, rather than Parkway West.

6. decline to grant leave to Union to construct Parkway West except for the acquisition of the land, the entry and egress pipeline, in particular, to facilitate the construction by Enbridge of the Parkway West gate station.

7. decline to grant leave to construct its Compressor D and Parkway West, and to construct the Brantford to Kirkwall 48" loop, pending the approval of the Settlement Agreement by the NEB, or the parties agreeing to a New and Approved Settlement Agreement.

8. in the event the NEB approves the Settlement Agreement or the parties agree to a New and Approved Settlement Agreement, grant Union leave to construct one 44,500 compressor at Parkway West station, which would be used, together with the two compressors at Parkway, to service immediate and short term growth requirements and provided LCU protection to the extent practicable.

9. in the event the NEB approves the Settlement Agreement or the parties agree to a New and Approved Settlement Agreement, and TCPL agrees to expand the Bram West Maple corridor as provided for in the Settlement Agreement or in the New and Approved

Settlement Agreement, grant Union leave to construct the 48" loop from Brantford to Kirkwall.

10. decline to pre-approve Union's section 36 request to allow recovery in rates of the cost consequences of its two proposed long term contracts with TCPL to serve its northern and eastern delivery area customers from Parkway.

11. decline to pre-approve Union's section 36 request to include the cost consequences of its Parkway West and Brantford/Kirkwall Compression D projects in rates.

12. decline to approve Enbridge's approach to rate 332.

13. examine, in a separate proceeding, the prudency of the Settlement Agreement.