EB-2012-0451

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF an application by Enbridge Gas Distribution Inc. under section 90 and 91 of the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15 (Schedule B) for an order or orders granting leave to construct a natural gas pipeline and ancillary facilities in the Town of Milton, City of Mississauga, 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 IN THE MATTER OF an application by Enbridge Gas Distribution Inc. under section 36 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B) for an order or orders approving the methodology to establish a rate for transportation services.

FINAL SUBMISSIONS OF
ENERGY PROBE RESEARCH FOUNDATION
("ENERGY PROBE")

November 15, 2013

SUMMARY

i. Enbridge Gas Distribution Inc. ("**Enbridge**", **EGD** or the "**Applicant**") has applied for Leave to Construct the GTA Project comprised of two Segments - A and B - and the associated Parkway West facilities. EGD has also applied for approval of the rate methodology (Rate 332) for transmission services along Segment A of the proposed GTA Project.

ii. Leave to Construct Applications, including the GTA Project, are filed under sections 90 and 91 of the *Ontario Energy Board Act, 1998* (the OEB Act). The test for an application is the public interest as set out explicitly in section 96 of the statute.

> If, after considering an application under section 90 … the Board is of the opinion that the construction, expansion or reinforcement of the proposed work is in the *public interest*, it shall make an order granting leave to carry out the work.

iii EGD amended its Application in July 2013 to change the size and terminus of Segment A - to an open access NPS 42 Albion Pipeline Transmission (60%) and Distribution (40%) line.

iv. In its revised Application EGD requested **two** orders:

- pursuant to section 90 and 91 of the Ontario Energy Board Act, 1998, S.O.1998, c-15 (Schedule B) an Order(s) granting leave to construct the GTA Project - Segment A, including Parkway West Gate Station to Albion Road Station, as a NPS 42 pipeline, and other facilities;

- pursuant to section 90 and 91 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c-15 (Schedule B), an Order(s) granting leave to construct the GTA Project - Segment B.

v. In updating its evidence, EGD did not, in Energy Probe's view, correctly apply the Boards E.B.O. 134 Economic Tests and EB-2012-0092 Guidelines to Segment A, but rather modified its *combined* (Segment A and Segment B) Economic Evaluation under E.B.O 188 Distribution System Expansion Guidelines. Accordingly, there is no *separate* Segment A E.B.O. 134 Economic evaluation on record. This deficiency is important because of subsequent events affecting the transmission function and timing of construction of the Segment A EGD Albion Pipeline (Transmission).

vi. On October 31, 2013 EGD and Union filed the four-party (EGD, Gaz Metro, Union and TCPL) Settlement Agreement, indicating to the Board that this was subject to approval of the National Energy Board.

vii. The Settlement Agreement has both direct and indirect implications for the GTA Project, particularly approval of Segment A and also has long term cost/benefit implications regarding the decision of EGD to replace current Long Haul TCPL Transportation with Short Haul transportation, in order to improve market access.

viii. Energy Probe submits that the requirement for the NEB to approve the Settlement Agreement is now a critical *condition precedent* to the Board granting EGD Leave to Construct for Segment A (Albion Pipeline Transmission) because 60% of the Capacity is dependent on EGD executing long term transportation contracts with ex-franchise transportation shippers. The Settlement explicitly prevents EGD from doing this and also is precedent to TCPL building the connecting downstream Kings North facilities.

ix. Union accepts that NEB approval of the Settlement is a precedent to its Brantford-Kirkwall project.

x. EGD's position is that Segment A of the GTA Project should proceed as an NPS 42 ***distribution*** pipeline with distribution customers having full responsibility for the costs. In our view this would not meet the public interest requirement of Section 96 of the Act.

RECOMMENDATIONS

xi. Energy Probe submits that the Board should, in addition to its standard conditions, also Condition its Order granting Leave to Construct Segment A of the GTA Project upon EGD demonstrating in its 2015 rate case, that it has executed long-term transportation contracts for the Segment A EGD Albion Pipeline. The cost consequences of not providing this proof would be determined at that time.

xii. With respect to Segment B, Energy Probe agrees with EGD's evidence that reinforcement of the GTA distribution system is urgently required. Union's Application for Loss of Critical Unit protection at Parkway West (EB-2012-0433) is one component of this. The other is to fix the reliance on a Single XHP line serving the Downtown core and a Single XHP Link between western and eastern parts of the GTA Project Influence Area.

xiii. Enbridge's system is designed at peak hour on a peak day. In principle, Energy Probe supports DSM and acknowledges that DSM could provide some benefits at peak in addition to annually. However, in considering the evidence in this proceeding, Energy Probe submits that due to the uncertainty raised around the timing, DSM is not a preferred alternative to the proposed facilities, specifically to Segment B.

HOW THESE MATTERS CAME BEFORE THE BOARD.

1. Enbridge Gas Distribution filed an Application dated December 12, 2012 for leave to construct the Greater Toronto Area Pipeline Project (the "GTA Project").

2. The Board issued a Notice of Application dated March 5, 2013.

3. On April 17, 2013, the Board issued Procedural Order No. 1 and its Cost Eligibility Decision for both the Enbridge GTA Project and Union Parkway West Project. Within Procedural Order No. 1 the Board provided dates for both an Issues and Process Conference and an Issues and Process Day.

4. On April 26, 2013, the Board held an Issues and Process Conference for parties to discuss the Draft Issues List and the process the Board should follow when hearing these applications.

5. On May 8, 2013 The Board Issued Procedural Order #2 in which the Board determined it will combine the EB-2012-0451, EB-2012-0433 and EB-2013-0074 proceedings. The Order established the dates for filing Interrogatories on the Applicants evidence.

6. On, June 21, 2013 Union and Gaz Metro filed a motion with the Board requesting inter alia:

    A declaration that the Board's Storage and Transportation Access Rule ("STAR") applies to Segment A of the Enbridge Gas Distribution Inc.'s ("Enbridge") GTA Project.

    An order staying the GTA Project until such time as Enbridge has initiated an open season pursuant to STAR in respect of the new capacity on Segment A of the GTA Project.

7. On July 22, 2013, Enbridge filed an update to its evidence in relation to Segment A of the GTA Project (EB-2013-0451). Segment A is now proposed to begin at the Parkway West Station as opposed to Bram West interconnect. The Board provided for a new period of public notice and updated the hearing schedule.

8. On July 23, 2013 In Procedural Order #6 the Board established a new Notice Period and new Schedule including a second round of IRs on the updated Evidence.

9. On Monday, August 28, 2013 a Settlement Conference was held. No Settlement was reached.

10. A Pre-Hearing Conference was held on September 5, 2013.

11. On September 11, 2013 EGD Union and Gaz Metro and TCPL notified the Board and Parties to the proceeding that they had entered into a Term Sheet regarding a Settlement of their Issues.

12. On Thursday, September 13, 2013 a Technical Conference was held on the Term Sheet.

13. On September 16, 2013 the Oral Hearing commenced. It was completed on October 9, 2013.

14. On October 31, 2013 EGD and Union filed the Settlement Agreement, indicating this was subject to approval of the National Energy Board.

OVERVIEW OF GTA PROJECT

15. Enbridge Gas Distribution Inc. ("**Enbridge**", **EGD** or the "**Applicant**") has applied for leave to construct the GTA Project which, as described below, is comprised of two segments - referred to as Segments A and B – together with the Parkway West facilities. Enbridge has also applied for approval of the rate methodology (Rate 332) for transmission services along the EGD Albion Pipeline (Segment A) of the proposed GTA Project.

16. According to EGD the GTA Project is "first and foremost a distribution project that has been designed to fulfill multiple distribution purposes and to address multiple needs of the distribution system". EGD states that at the highest level, the purpose of the GTA Project is to reinforce Enbridge's Extra High Pressure (XHP) pipeline system to manage operational risks and meet growth needs in a prudent manner.[1][2]

17. However, following its Application Update in July 2013, the Segment A starting point was changed to Parkway West and the pipeline upsized to provide cross-franchise transmission capacity that is capable of addressing short haul market access requirements for the transportation of natural gas to Eastern Canadian Markets, (EGD, Union Gas and Gaz Metropolitan) and will, if approved, provide claimed associated benefits.

18. Segment A of the proposed GTA Project includes the installation of approximately 27 kilometres of NPS 42 XHP steel transmission and distribution pipeline to be located between the proposed Parkway West Station and the expanded Albion Road Station. The estimated Capital Cost of Segment A is $687 million.

[1] EGD AIC Page 2
[2] Exhibit A, Tab 3, Schedule 2, page 8, para. 27.

19. Segment B includes the installation of approximately 23 kilometres of NPS 36 XHP steel distribution pipeline that will commence at Enbridge's existing Keele/CNR Station and travel northeast for approximately 15.4 kilometres to the proposed Buttonville Station, located south of Highway 407 between Pharmacy Avenue and Warden Avenue. Segment B would continue south for the remaining 7.6 kilometres to just north of Sheppard Avenue, where it would tie into an existing NPS 36 pipeline. Segment B also includes an expansion of the existing Jonesville Station. The estimated Capital Cost of Segment B is $xx million[3]. The 2016 Revenue Requirement is $34 million.

20. The proposed Parkway West facilities are comprised of (a) a new gate station; (b) approximately 315 metres of NPS 36 XHP steel pipeline to connect the Parkway West Station to the existing NPS 36 Parkway North Line; and (c) new regulation to tie the Parkway North Line to the Mississauga South Line. The estimated Capital Cost of the Parkway West Facilities is $xx million[4]. In addition EGD will lease land and facilities from Union Gas.

LEGAL/REGULATORY FRAMEWORK FOR REVIEW OF LEAVE TO CONSTRUCT APPLICATION

21. Leave to Construct Applications, including the GTA Project, are filed under sections 90 and 91 of the *Ontario Energy Board Act, 1998* (the OEB Act). The test for an application is the public interest as set out explicitly in section 96 of the statute.

> If, after considering an application under section 90 … the Board is of the opinion that the construction, expansion or reinforcement of the proposed work is in the *public interest*, it shall make an order granting leave to carry out the work.

[3] Exhibit C, Tab 2,Schedule 1, page 4 redacted Confidential
[4] Ibid 3

22. The Board's Practice has been to ensure Leave to Construct projects are first examined by the Hydrocarbon Pipeline Coordinating Committee. The Board then considers the following matters in assessing the "public interest":

- project need; e.g. customer growth; diversity of supply,
- the economic feasibility and other benefits of the project; e.g. EBO 169 and180,
- project alternatives; e.g. physical routing; DSM,
- landowner and environmental impacts; routing, mitigation, and
- current technical and safety requirements. e.g. class of use.

23. In granting Leave to Construct the Board often imposes both standard Conditions of Approval including the requirements to obtain all and necessary permits, licences etc... The Board may, in addition, also impose special Conditions such as filing of contingent permits and other approvals that the project(s) require e.g. NEB approvals.

STRUCTURE OF ENERGY PROBE SUBMISSIONS

24. Energy Probe will structure its submissions in accordance with the Issues List. Under each of the Issues we will identify the main sub-issues and indicate where we are in substantive agreement with the Company's evidence supporting the Application, where we take no position and where we disagree with the Companies evidence and position. In the latter case, we will discuss our concerns and propose alternatives for consideration by the Board.

ISSUE A1. ARE THE PROPOSED FACILITIES NEEDED?

Considerations may include, but are not limited to, demand, reliability, security of supply, flexibility, constraints, operational risk, cost savings and diversity as well as the Board's statutory objectives.

Segment A

Sub Issue	Energy Probe Position
demand	***Concern with Volume/throughput forecasts for both distribution and transmission***
reliability	No Specific Issue
security of supply	*Diversity of Entry Points to System no issue*
flexibility, constraints	***See Security of Supply***
operational risk	no Specific Issues
cost savings and diversity	***Change from Long Haul to Short Haul transportation*** ***WSB vs. shale gas landed gas price forecasts that favor SH***
Board's Statutory objectives	***Segment A is both a transmission and distribution line***

Segment B

demand	Agree with 10 year customer additions forecast. ***Concern with Volume forecast and peak demand (DSM)***
reliability,	Agree with Company evidence for increased reliability for Segment B
security of supply,	Issue for Segment A
flexibility, constraints,	No Specific Issues
operational risk	No Specific Issues
cost savings and diversity	Issue for Segment A
Board's Statutory objectives	No specific issue

CUSTOMER AND VOLUME GROWTH

25. In accordance with E.B.O. 188 Guidelines, EGD has provided customer and volume forecasts for distribution system growth for 10 years after the 2015 In-Service date. These data pertain to the GTA Influence Area and for both Segments A and B. As will be discussed later, Segment A is a combined transmission and distribution pipeline and carries more ex-franchise volumes compared the in-franchise distribution volumes.

26. Energy Probe agrees EGD's in-franchise customer addition forecast is reasonable and conforms to E.B.O. 188 Guidelines:

Years	Residential	Commercial	Apartment	Industrial	Total
2004-2014	151,382	14,311	450	54	166,197
2015-2025	146,672	13,977	750	24	161,423

27. EGD is forecasting GTA Influence Area volume growth of 706,621 10^3 m^3 cumulative from 2015-2025.

28. EGD's evidence indicates that one of the major variables affecting the Peak Demand and volume forecasts is the load of the major industrial and power generation customers, including the duty cycle of the Portlands Energy Centre. Another factor is declining average use of heat sensitive General Service customers. The latter is also particularly affected by conservation, including both "natural conservation" and the DSM programs of EGD and others.

SECURITY OF SUPPLY, DIVERSITY AND LANDED PRICE OF GAS

29. EGD indicates one of the primary purposes of the GTA Project, particularly Segment A is improved Market Access. This is defined by EGD as access to firm short haul transport service to closer supply basins and competitive market hubs that it claims is critical for customers in the GTA Influence Area, Enbridge's EDA service area, other

parts of eastern Ontario and Québec. EGD claims it allows customers to have access to more diversified supply sources and contracting avenues, which could enhance the competitiveness of industry and stimulate growth.

30. EGD is reducing 400 tj/day Long Haul transport from the Western Sedimentary Basin. This is a mixture of FT and STFT. There are several cited reasons for this:

- Gas price differentials Empress-Dawn
- Diversity of Supply
- Restructuring of the TCPL Mainline and Tolls

The October 31, 2013 a four-party LDC (Enbridge, Union, Gaz Métro) Settlement Agreement with TCPL that has been filed in these proceedings, seeks to resolve the obstacles to improved market access.

31. Mr. Henning of ICF is adamant about the proposed changes:

> …it's quite important to the consumers in Ontario because absent that … if you're forced all the way back to Empress and collecting those demand charges while you're shrinking that basis, Ontario will have some of the highest gas prices in all of North America. And that will affect industry in Ontario, it will put upward pressure on electricity prices in Ontario.[5]

32. In its response to Undertaking J6.X, Enbridge evaluated the impacts of the Settlement on gas supply benefits under a variety of basis and utilization assumptions. In all cases, the gas supply benefits were still positive. The analysis identifies an additional $49-69 million/year in gas supply benefits as a result of the Settlement attributable to serving the Eastern Delivery Area (EDA). Accordingly, the GTA Project Segment A economics are driven by expected forecast landed gas cost savings.

[5] 2Tr.154-155

33. From an EGD ratepayer perspective there are two options to deal with this supply/ transportation benefit/risk:

a) *either* to trust EGD (and Union) to provide System Gas (sales service gas) at a Landed Price that is competitive and accept their assurances that the proposed Projects are required to achieve this with reasonable consequential transition costs.

b) *or* for EGD (and Union as operator of the Dawn-Parkway system) as set out the EB-2013-0459 Settlement Agreement to provide the Board with a detailed Long-term (2015-2025) Gas Supply and Transportation Plan with alternatives examined in more depth than in the current LTC proceeding. The key is a base case outlook based on the Settlement Agreement and "what if" scenarios if this is not approved by the NEB.

34. Energy Probe favours the second alternative (b) and suggests that the timing and logistics to achieve this can be made to fit into EGDs 2014 regulatory process. We note that Gaz Metro filed an extensive application to obtain approval for its new gas-supply plan based on shifting to new gas supply sources and Short Haul transportation. As stated by Mr. Rhéaume of Gaz Métro,

> About a year ago, Gaz Métro went to its regulators with various intervenors to discuss where Gaz Métro should supply its market. Obviously it was the issue of Empress versus Dawn. After a long process at the Régie, the Régie concluded that Gaz Métro needed to shift its supply from Empress to Dawn.[6]

The Regie heard this application over several months before issuing its approval.

SEGMENT A IS AN EX-FRANCHISE TRANSMISSION AND IN-FRANCHISE DISTRIBUTION PIPELINE

35. EGD originally filed Segment A as an in-franchise ***distribution*** pipeline with TCPL building the other facilities to deal with the Albion-Maple bottleneck and downstream Union and Gaz Metro transportation requirements. After negotiations between TCPL and EGD, Segment A was planned as a joint venture with TCPL taking up to 1200 tj/d and EGD up to 800 tj/d.

[6] 8Tr.52

36. Following the NEB RH-003-2011 Decision, TCPL decided to become a (sole) shipper on the Albion Pipeline under the new Rate 332. When EGD terminated the MOU in July 2013, in part due to concerns about STAR compliance, EGD then took the major step of issuing an Open Season and then becoming the potential Transmission provider on the Albion Line from Parkway to Albion.[7] No contracts have been executed yet because the operation of EGDs Albion transmission pipeline as a merchant pipeline is now contingent on NEB approval of the Settlement Agreement.

Proposed Pipeline	Size	PW Inlet pressure	Capacity GJ/d	EGD Need 2016	Shippers (OS) 2016	Capital Cost $m	2016 Revenue Requirement	Allocation of cost	2016 Transmission Revenue
Distribution	NPS36	935 psig	800TJ/D	800TJ/D[1]	0	$632[2]	$28.6 m[3]	100% D	$0
Distribution +Transmission	NPS42	935 psig	2000 TJ/D	800TJ/D 170TJ/D	760 TJ/D (+170 EGD)	$687	$33.7 m[3]	$13.5 m D $20.2 m T	$20.2 m (incl. EGD)

37. EGD now positions the EGD Albion Pipeline as the answer to all market access issues under the rationale of optimization of the gas transmission system in Ontario:

> …this design for segment A of the GTA project provides for rational infrastructure planning for transmission purposes. It avoids duplicative facilities that would otherwise be required if market access were to be provided independent of this project. It reduces environmental footprint, reduces impacts in communities that live along these lines, and to that extent, there's significant benefits from optimizing the GTA project for market access, in addition to building for distribution needs.[8]

Energy Probe disagrees with EGD.

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[7] The Settlement Agreement also refers to the "Albion Pipeline" –a TCPL build from Albion to Maple
[8] 4Tr.89.

38. The decision of EGD to position the EGD Albion Pipeline as a 42" ex-franchise merchant pipeline of up to 1200 tj/d capacity, plus up to 800 tj/d in-franchise distribution capacity exposes EGD distribution customers to significant incremental risks:

- Uncertainty whether the NEB will approve the Settlement Agreement that contains inter-alia the provisions that EGD will not by-pass TCPL and TCPL will build the downstream facilities from Albion to Maple.
- Potential delays in NEB Approvals that will prevent merchant gas (Union, Gaz Metro et al) flowing in fall 2015 as planned.
- Open season for remaining capacity to follow NEB approval of Settlement Agreement.
- Un-contracted capacity due to delays in TCPL building downstream capacity from Albion to Maple.
- Un-contracted capacity due to turnback at any point in the future.

EGD's Position is that:

- The Albion Pipeline is economically justified for distribution service only under E.B.O. 188 guidelines for distribution pipelines. (in our view this has not been properly demonstrated by EGD)
- Any shortfall in transmission revenues, due to delays in NEB approvals and/or build of connected facilities, will be recovered from in-franchise distribution customers.

39. We will address the risks to ratepayers resulting from the Updated July 2013 Application, rather than try to turn the clock back to early 2013 and EGD's original Segment A distribution pipeline application.

40. Energy Probe strongly suggests that EGD ratepayers be indemnified by EGD for any revenue shortfall due to the EGD Albion Pipeline:

- Overruns in In-Service Capital Cost allocated 60:40 transmission:distribution.
- Annual Revenue Requirement recovered in rates 60:40 transmission:distribution.
- Any shortfall in revenue from transmission services be deferred and amortized and recovered as part of the cost responsibility of the transmission service
- Distribution service be allocated 40% of annual revenue requirement based on distribution service capacity of up to 800 tj/d. Any capacity allocated to Direct Purchase customers should use the same charge determinants rather than Rate 332 or range or other rates.
- Any surplus *distribution capacity* to be sold as a Transactional Service and net revenues allocated to distribution customers based on cost causality principles.

41. Energy Probe suggests that the Board, requires that these matters become part of a Settlement Conference followed by an oral hearing either in EGD's EB-2013-0465 proceeding or a later rate case.

ISSUE A2. 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 E.B.O. 188 AS APPLICABLE?

Energy Probe's main Issue is EGD's Economic Evaluation <u>Methodology.</u>
Does it comply with the Board's EBO 169 and EBO 188 Guidelines and EB-2012-0092 Filing Guidelines for Transmission Pipeline Applications?

42. EGD's Economic Evaluation that combines Segments A and B as if they are distribution reinforcement pipelines to which E.B.O. 188 Guidelines apply:

DR. HIGGIN

If we could look at your Exhibit, E, tab 1, schedule 1 paragraph 5.

> "The overall economics combine the costs and quantifiable benefits of both segments. As a result, the discounted cash flow of DCF was prepared on the basis of the entire project over a 40-year horizon, which is in accordance with both EBO-188 and EBO-134."

So that's the framework that you've adopted; correct?

MR. MURRAY: That's correct.

43. As we demonstrated in Exhibit K9.1, following the July Application Update, Segment A is now a combined transmission/distribution pipeline, which functions as a merchant pipeline under the proposed Rate 332, whereas Segment B is a distribution reinforcement pipeline.

44. Accordingly, as K9.1 shows, the analogy for the Segment A Albion Pipeline, is Union's Dawn–Parkway System that functions both as in-franchise distribution and ex-franchise transmission pipeline. In its EB-2013-0074 Application, Union has correctly applied the methodology in Boards EBO 169 Guideline and the Filing Guidelines on the Economic Test for Transmission Pipeline Applications.

45. We contend EGD has NOT correctly applied the Boards EBO 169 Guideline and the Filing Guidelines on the Economic Test for Transmission Pipeline Applications.

- First, by combining Segments A and B into a single Economic Evaluation. In our view, that would was appropriate for the original Application and EBO 188 distribution reinforcement Guidelines would apply.
- Second, by **not** undertaking a separate Economic Evaluation for Segment A and accordingly applying the EBO 169 and Transmission Filing requirements, as Union did in the EB-2013-0074 the Application for its Brantford-Parkway pipeline.

46. The outstanding question is what are the implications for the GTA Project Economic Evaluation? As discussed with EGD Witnesses, the differences between Union's correct approach and EGD's incorrect approach are there, but these may not be material to the final outcome. We believe the problem is that Segment A "morphed" into a combined Transmission and Distribution Pipeline, but the Economic Evaluation methodology did not follow that change. If the economic evaluation results were marginal, then we would have requested an Undertaking reworking the assumptions and numbers but as noted in the Transcript we did not.

ISSUE A3. ARE THE COSTS OF THE FACILITIES AND RATE IMPACTS TO CUSTOMERS APPROPRIATE?

Energy Probe's primary sub-issues related to Segment A are
• **Incremental capital cost of Segment A to accommodate ex-franchise shippers**
• **Revenue forecasts for Rate 332 and potential for under-recovery of allocated revenue requirement**
• **Allocation of a portion of Segment A capacity to Direct Purchase in-franchise customers**

47. Several of these issues have been discussed above. Detail on Rate Impacts is limited and we reference Undertakings J.9.1 and J9.8 as a summary of these. This is an LTC Application and there remain several important outstanding cost allocation and rate design issues, particularly now that Segment A is now a combined Transmission and Distribution pipeline.

48. From a ratepayer perspective, it is unreasonable for EGD to assume ratepayers have any cost responsibility for additional capital or operating costs related to changing the terminus to Parkway West and upsizing Segment A from 36" to 42". Even 36" is probably oversized for in-franchise distribution purposes, given forecast peak demand and the identified upstream potential transportation contracts for 400 tj/d Dawn-Parkway (Union) and 200 tj/d from Niagara to Parkway (TCPL). The remaining capacity (600 tj/d) is for growth. It may be EGD's plan to sell this as a Transactional Service on a short-term basis. There is no evidence on the latter.

49. We disagree with EGD's position that upsizing Segment A to 42" (2000 tj/d) provides additional benefits in-franchise customers. We submit this is not the case. A 36" pipeline (1200 tj/d) connected at Parkway to transport in franchise gas volumes from Dawn-Parkway and Niagara-Parkway provides all of the same benefits without the costs and risks.

> Ms. Giridhar:
> The relevance the Settlement Agreement is that it has charted a path forward for market access. This Board, in a ruling to Union Gas last year or the year before – last summer, urged the LDCs to work with TransCanada on a rational expansion of our systems.
>
> We have done that. We have identified a path forward for market access. The GTA Project was originally filed as a distribution project of an NPS 36. It is now an NPS 42. *For less than a 10 percent incremental cost, we're able to accommodate that market access and provide significant cost savings to our customers* …emphasis added[9]

[9] 9Tr.98-99.

50. Ratepayers will have a cost responsibility amounting to $632 million for a Segment A 36" distribution line that provides market access, entry point diversity and all of benefits which EGD claims. They will **not** receive any *incremental benefit* from upsizing to 42". The only in-franchise additional benefit is the 170 tj/d capacity to supply EGD's EDA. However, the 36" line has a capacity of up to 1200 tj/d and will have adequate capacity to meet this requirement.

51. By upsizing to a 42" pipeline (from a 36" distribution line) EGD is making an explicit choice to enter the market for ex-franchise transportation services. EGD's case for this decision is that it "represents rationalization of the provincial gas transportation system"[10]

> Ms. Giridhar:
>
> …this design for segment A of the GTA project provides for rational infrastructure planning for transmission purposes. It avoids duplicative facilities that would otherwise be required if market access were to be provided independent of this project. It reduces environmental footprint, reduces impacts in communities that live along these lines, and to that extent, there's significant benefits from optimizing the GTA project for market access, in addition to building for distribution needs.[50]

52. In our view the case for the "collaborative build" has not been demonstrated. TCPL has allowed the by-pass of its current and future GTA facilities as part of the Settlement Agreement[11]. That does not equate either to saying this is a rational expansion of the Ontario transmission system as evidenced by the fact that this expansion is contingent on upstream and downstream facilities that must be built by Union and TCPL or a reason that EGD distribution Customers should pay for this. Any way as EGD states:

> "it's only an extra 10% *incremental cost,*"[12]

[10] 4Tr.89.
[11]
[12] Ibid 8

53. Accordingly, we submit that:

a) If the Settlement Agreement is approved by the NEB, this Board should place the full cost responsibility for the *incremental* Capital Cost ($687-$632 million) of upsizing Segment A to 42" upon EGD's Albion Pipeline Transmission Service by allocating the incremental cost 100% to Transmission Service together with a share of the base Capital amount $632 million. This latter amount should be based on Capacity at Peak Day and allocated 60:40 transmission; distribution. This is not EGD's proposal- which is to allocate the total Capital cost (base capital plus incremental) to transmission shippers and ratepayers 60:40.

b) If the NEB does not approve the Settlement, then once other regulatory moves indicated therein are done, as a condition of its approval in this case, the OEB should make EGD and its shareholder responsible for all of the incremental cost of the 42" pipeline relative to a 36" distribution pipeline. We have recommended a condition to this effect in the Summary.

54. As noted above, we are also concerned that the revenues forecast for Rate 332 may not happen. This is particularly true for the early years until both upstream (Union) and downstream (TCPL) facilities are built and in service.[13] In addition, if market dynamics change there could be unutilized/uncontracted capacity due to various factors including turn-back. We reiterate our recommendation above that EGD indemnify ratepayers from all negative impacts from the Albion Pipeline Third Party Transmission Service.

55. It appears from the oral hearing that EGD may be planning to offer capacity on Segment A to both ex-franchise shippers and also to in-franchise unbundled direct purchase customers:

[13] J6.10

Ms. Giridhar:

…the GTA project is reserving 200 tjs per day for our direct purchase customers for delivery into the system, into the GTA system, and so we have had some level of contact with our direct purchase customers already, and we have a commitment on approval of these facilities to initiative a more full consultative with our direct-purchase customers to understand what their needs are and how we can ensure the delivery arrangements work for them …[14]

56. Unbundled Direct Purchase customers currently deliver their gas to EGD's City Gate receipt point(s) and then pay distribution rates for delivery to the plant gate. This transcript reference seems to suggest that by contracting for capacity on Segment A either as a shipper either under Rate 332, or other rate, for example using surplus Segment A capacity, rather than paying the distribution charges as a distribution customer, in-franchise DP customers can by-pass in whole or part EGD's distribution system. If this interpretation is correct, then the Board should indicate in its Decision that *in-franchise DP customers* be required to pay appropriate rates on Segment A that do not create negative cost consequences for EGD's other in-franchise customers.

57. This Issue should be examined further in EGDs next rate case.

ISSUE A4. WHAT ARE THE ALTERNATIVES TO THE PROPOSED FACILITIES? ARE ANY ALTERNATIVES TO THE PROPOSED FACILITIES PREFERABLE TO THE PROPOSED FACILITIES?

58. We have discussed from an EGD in-franchise customer's perspective our concerns with Segment A. The alternative to EGD's Updated Application (to revert to a 36" distribution pipeline.) is no longer realistic.

[14] 9Tr.30-31.

The Settlement Agreement has moved the yardsticks forward and our analysis and recommendations in this submission are designed to protect ratepayers from any resulting adverse cost consequences.

The remaining Issues relate to Segment B.

Distribution System Reliability -Operational Considerations
Demand Side Management -Increased DSM to reduce demand

59. Energy Probe agrees with EGD's evidence that reinforcement of the GTA distribution system is urgently required. Union's Application for Loss of Critical Unit protection at Parkway West (EB-2012-0433) is one component of this. The other is to fix the reliance on a Single XHP line serving the Downtown core and a Single XHP Link between western and eastern parts of the GTA Project Influence Area.

60. EGD's evidence is that Segment B eliminates the east-west bottleneck on the XHP system; this allows gas to be available from more diverse supply points and it aids in daily load balancing required to meet upstream contractual obligations. Segment B also provides looping of part of the Don Valley line with the proposed new stations providing additional feeds into the XHP distribution system. We agree with EGD that the GTA Project allows for more operational flexibility during both planned activities, as well as unexpected upset conditions.

61. In addition EGD notes there are potential compliance issues:

> "The NPS 26 and NPS 30 Don Valley lines both operate above 30% SMYS, both have a wall thickness that is thinner than a pipeline that would be installed today, and both are critical to system operation given the supply consequences of an outage of these pipelines. …"

> "The Company's ability to provide reliable service is at risk given the lack of diversity of the supply path in these two lines, the limited flexibility of other pipelines to back-feed the same geographic areas, and the unavailable capacity to reduce these lines to below 30% SMYS on a temporary or operational basis to mitigate operational risk in normal operating conditions. The absence of diversity and flexibility in periods of higher demand increases the potential risk incurred by the Company as it may limit its ability to either respond in a timely manner or maintain reliable supply to customers. The choice between these two options is not considered to be reasonable when system reinforcement mitigates the risk with the existing infrastructure."[15]

62. Enbridge began planning for the GTA project in 2010[16] and considered other alternatives prior to proposing the GTA Project. Specifically Enbridge considered Demand Side Management (DSM) as one alternative to meet the project objectives. Enbridge concluded that conservation efforts cannot be expected to replace the capacity within the system due to the lowering of pressures on large diameter, higher pressure lines, or create the needed diversity in the supply chain.[17] Enbridge states that if there was no load growth, the project would still be required to meet the other project objectives.[18]

63. In order to meet the "public interest" test with respect to the consideration of alternatives to the GTA Project, in Energy Probe's view, Enbridge's original evidence regarding DSM potential was at an extremely high level and did not include any reports, studies or quantitative analysis to demonstrate that additional DSM was not a viable alternative to the GTA project as a whole or individual elements of the project that could be cost effectively deferred or avoided. Enbridge acknowledged that it did not undertake any in-depth analysis of potential incremental DSM

[15] Exhibit A, Tab 3, Schedule 3, pages 17-18, para 32.
[16] Enbridge Argument-In-Chief, Page 21
[17] Exhibit A, Tab 4, Schedule 7
[18] Exhibit I.A4.EGD.ED.20

measures, programs and budgets given, in its view, the uncertainty and challenge in scaling DSM programs to address the growth objective, and given that reliability and upstream concerns cannot be resolved by any DSM efforts. In Enbridge's view, DSM measures are not a viable alternative to the GTA project.[19]

64. During the hearing, Enbridge explained that the GTA Project is a multi-faceted project with several objectives dealing with limitations on the current system that are coincident and so focusing DSM to meet one objective i.e. load growth would not be appropriate. Enbridge stated it screened out DSM in 2011 in part due to the order of magnitude of incremental DSM required to meet its proposed 30% SMYS pressure reduction (a 20 fold increase over current levels) and 600 TJ supply shift (a 60 fold increase).[20] Enbridge also believes its objectives to have a second feed into downtown Toronto of flexibility and diversity within the XHP system cannot be achieved with DSM.[21]

65. Expert evidence filed by Environmental Defense (ED) and Green Energy Coalition (GEC) permitted a more thorough examination in this proceeding of whether expanded DSM could be considered as a viable option to defer or avoid some or all of the capital investments.

Environmental Defense & Green Energy Coalition Evidence

66. Enbridge sought the Board's approval to update its 2012-2014 DSM plan in EB-2012-0394. Following consultation with stakeholders the proposed 2013 and 2014 DSM budgets were set at $31.58 M and $32.16, respectively. The Board approved these amounts as part of the Settlement Agreement in EB-2012-0394 on an interim basis to provide an opportunity for the 2014 DSM budget to be further reviewed and incrementally increased as required in the current proceeding EB-2012-0451.

[19] Exhibit I.A4.EGD.ED.20
[20] Transcript Pages 69-70
[21] Transcript 5, Page 70

The Board indicated it did not have sufficient evidence in EB-2012-0394 to opine on DSM as an alternative to the GTA project.[22]

67. In this proceeding (EB-2012-0451), ED filed expert evidence prepared by Ian Jarvis (Enerlife Consulting Inc.) that estimates the DSM load reduction potential for apartment and commercial customers in the GTA area and includes the evidence of GEC with respect to DSM potential for residential and industrial customers (also as per Marbek Report), in formulating its conclusions.

68. GEC filed expert evidence prepared by Chris Neme & Jim Grevatt (Energy Futures Group) and Paul Chernick (Resource Insight, Inc.). Energy Futures Group (EFG) assessed how much additional efficiency savings is achievable in aggregate (top down approach looking across all sectors) based on the experience of leading jurisdictions. EFG specifically estimates the DSM savings potential for residential and industrial customers, which was provided to Enerlife for its analysis. EFG puts forward an estimate of how much additional peak hour savings could be achieved in the geographic area driving the need for Segments B1 and B2 if Enbridge were to ramp up its DSM investment beginning in 2014. The estimate of the magnitude of additional peak hour savings that Enbridge could realize from DSM was provided to Resource Insight, Inc. Resource Insight, Inc. then developed a mix of alternatives that could, in its view, potentially defer the need for the pipeline to meet load growth.[23]

69. Enbridge has forecast load growth in the influence area of approximately 18 TJ per peak day. Enbridge included planned DSM in its demand forecast for the purposes of planning and designing the GTA Project. Enbridge estimates that its planned DSM programs will deliver in the order of 12,000m^3 per hour (9 TJ/day) peak demand reduction savings each year.[24]

[22] EB-2012-0394 Decision and Order on Settlement Agreement, July 4, 2013, Page 3
[23] Exhibit L.EGD.GEC.2, Page 1
[24] 1.A4.EGD.ED.14, Page 2

70. To offset customer load growth Enbridge estimates an additional 25,000 m^3 per hour (18 TJ/day) of DSM is required each year for a total of 37,000 m^3 per hour (27 TJ/day) in peak demand reduction. So roughly double what the planned DSM programs are expected to achieve is incrementally required to meet the forecasted load growth.

71. In Energy Probe's view, the following key issues need to be addressed in considering ED and GEC's evidence and the potential of expanded DSM to defer or avoid any GTA Project facilities:

a. Is it feasible and cost-effective for Enbridge to ramp up its DSM as proposed by Enerlife, EFG or Resource Insight, Inc. to achieve the required incremental peak demand reduction?

b. In addition to meeting load growth, do the DSM proposals meet the other project objectives, specifically the required pressure reductions in the Don Valley and NPS 26 pipelines?

c. If approved, could Enbridge implement an expanded and accelerated DSM plan by the required in-service date of November 2015 for the GTA project so that the project benefits are realized?

Enerlife Consulting Inc. Report Evidence concerning Demand Side Management Potential in the GTA (June 28, 2013)

72. Enerlife took a different approach from the Marbek DSM Potential Study conducted for Enbridge in 2009 that relied on technologies, assumed penetration levels and engineering calculations. Enbridge characterizes Marbek's approach as bottoms-up in determining what can actually be achieved by customers.[25] Enerlife used a top-down Performance-Based Model derived from Enerlife's database of actual energy performance that includes data for 638 buildings. The model analyzes actual,

[25] Transcript 5, Page 41

benchmarked energy use of different building types and establishes the potential savings due to all buildings reaching intensity levels by one half (median) or one quarter (top-quartile) of the peer group.[26]

73. Based on its Performance-Based-Model, Enerlife forecasts an annual average peak demand reduction potential through DSM of 30,300 m^3 per hour (37.5 TJ/day) at the top quartile level and 23,500 $m^{3/}$hr (17.7 TJ/day) at the median-quartile level by 2025.[27] The potential load reductions due to DSM was created from Enerlife's actual energy performance data for buildings.

74. Enerlife concludes that all load growth in the GTA 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.[28]

75. Enbridge accepts that DSM has some potential for decreasing peak loads but raised significant concerns with Enerlife's DSM approach to target peak loads given that Enbridge's current DSM programs are focused on lowering total annual consumption (not peak load) in order to be economic over the life of the program[29] and a change to this approach would mean a wholesale change to Enbridge's DSM approach.

76. Specifically, Enbridge stated that it is not aware of any DSM programs that target peak load and that it is standard practice to design, deliver and measure DSM programs that impact annual savings.[30] Enbridge claims it does not communicate, measure, or interpret DSM reductions on a peak hour basis[31]; it does not actively track or calculate the impact of specific DSM measures on peak hour[32]; nor has

[26] Exhibit L.EDG.ED.1, Page 3
[27]Exhibit L.EDG.ED.1, Page 2
[28] Exhibit L.EGD.ED.1, Page 2
[29] Enbridge Argument-In-Chief, Page 22
[30] Transcript 7, Page 3
[31] Exhibit !.A4.EGD.Ed.39
[32] Exhibit I.A4.EGD.GEC.35

Enbridge conducted studies on the impacts of individual DSM programs on peak demand.[33] Enbridge stated on numerous occasions that it does not have a verified link between annual and peak demands.[34]

77. Enerlife confirmed its performance based model forecasts the reduction in peak demand and its relationship to annual consumption reduction in the same way that Enbridge came up with its estimation. Enbridge provided several caveats to its estimation and does not see the relationship between peak load reduction and annual consumption as being verified on this basis.

78. In Energy Probe's view, many of the efficiency measures in Enbridge's 2012-2014 DSM Plan could provide some benefits at peak in addition to annually, however based on the evidence in this proceeding it is not clear what the direct impact of DSM on peak hour demand is. Energy Probe submits this information is needed before a DSM plan that targets peak load can be relied upon as an alternative to infrastructure projects.

79. In order to target peak load Enbridge indicated it would have to completely overhaul its DSM approach which would require an enormous amount of work and a lot of spending for research to understand the relationship between the load profiles of the different technologies and its impact on peak load which in Enbridge's view would not be cost-effective.[35]

80. Energy Probe notes that Enerlife did not undertake any detailed investigation, analysis and planning to quantify the DSM potential in the specific buildings themselves, nor did Enerlife prepare a specific DSM plan to meet its proposed DSM objectives. Enbridge would be required to undertake this as part of a new DSM plan. Enbridge notes its current DSM plan, designed with the goal to reduce annual

[33] Exhibit I.A4.EGD.CCC.21
[34] Transcript 7, Page 6
[35] Transcript 7, Page 4

throughput, was developed through discussions with stakeholders and ratepayers to arrive at the economic benefits and current level of DSM and. Energy Probe submits in order to be compliant with the Board's DSM Guidelines, considerable consultation with stakeholders and ratepayers would need to be undertaken if Enbridge's current DSM approach and targets were to change. As discussed in **below**, Energy Probe submits that the proposed in-service dates for the GTA Project make this exercise untenable in the current timeframe.

81. Enbridge estimates that if DSM were used to offset all of the forecasted growth, under a growth only scenario, an overall DSM budget twice the current level, with the entirety of the incremental spend used for the GTA Project Influence Area, is required every year moving forward. Specifically, Enbridge estimates that $15.5 million of its 2014 DSM budget is allocated to the GTA area in 2014, increasing incrementally from there to 2025 and an additional $33.7 million of incremental budget is needed in 2014 to offset growth, rising to almost $42 million in 2025.[36] Thus the total cost of DSM, to achieve peak reductions, would be $40 to $70 million per year for 10 years.[37] Enbridge noted in this proceeding that it has not fully utilized its DSM budget historically.[38]

82. Enerlife believes the top-quartile results are attainable on the basis that the buildings in their database are representative of the GTA (72% of buildings in the data set are in Ontario) with the majority in the GTA, the gas targets are road-tested and they have yet to find a building that cannot reach these kind of target levels. With respect to the ability to sign up enough participants, Enerlife believes that the level of interest is there and the biggest savings are with large building owners. Enerlife proposes that year one would target owners of large buildings and engage a total of 60 owners and identify about 80 of their high gas savings potential buildings. A similar model would apply for the apartment sector and lower

[36] Environmental Defense Cross Examination Document, Page 4
[37] Transcript 5, Page 94
[38] Exhibit I.A4.EGD.ED.20

penetration rates are projected in the model for residential and industry.[39]

83. Enbridge does not agree the penetration levels and savings proposed by Enerlife are attainable.[40]

84. Energy Probe notes there is no evidence in this proceeding that speaks to the use of performance-based conservation by other gas utilities. Enerlife indicated it is not aware of any gas DSM programs in other jurisdictions that employ performance based conservation.[41] Enerlife is also not aware of any utilities in major cities in North America using the Performance based model as a method for calculating DSM potential.[42]

85. With respect to other utilities using DSM to defer capital infrastructure, Enerlife points to Consolidated Edison of New York who targeted in part their DSM program to address opportunities to reduce the amount of distribution capital necessary, however it was related to electricity. Other than the Vermont Gas example, EFG is not aware of any gas companies actively using peak demand reduction targeted DSM to avoid large facility system reinforcements.[43]

86. In principle Energy Probe agrees that Enbridge and other electric and gas utilities under the Board's jurisdiction could do a better job of integrated resource planning to look specifically at demand and supply options including the potential of DSM in geographically targeted areas to defer or avoid facility additions, and that this examination should be conducted early on when limitations such as capacity and load growth issues are first identified on the system. Energy Probe believes it may be possible with enough lead time, planning and analysis to achieve some targeted system objectives through DSM measures rather than supply side measures.

[39] Exhibit M.ED.Ed.BdStaff.2
[40] Transcript
[41] Exhibit M.ED.BdStaff.4
[42] Exhibit M.ED.EGD.6
[43] Exhibit M.ED.EGD.6, Transcript 7, Page 87

However, Energy Probe submits that this would first need to be part of a Board led initiative to look at this type of an approach and the benefits and risks on a generic basis to provide any resulting direction to all gas and electric utilities.

87. In considering the above, Energy Probe submits that given there is not a clear understanding at this time of the impacts of DSM on peak load; there are no examples of other gas utilities that have successfully implemented peak demand reduction targeted DSM to avoid large infrastructure; and it is very unlikely a complete overhaul of Enbridge's DSM plan could be implemented at the scale proposed in the timeframe required; Energy Probe submits ED's performance-based DSM is premised on too many uncertainties to be relied upon as an alternative.

Energy Futures Group (EFG) Report, DSM Potential in the GTA, June 28, 2013

88. EFG calculates that Enbridge is forecasting that it will achieve annual efficiency savings of approximately 0.50% of sales in the GTA based on recent historical experience which is lower than it is forecasting that it will achieve in its entire service territory (0.65%) and lower than five leading North American gas utilities are achieving (Questar, Interstate Power and Light, Vermont Gas Systems, Xcel, National Grid).[44] EFG's evidence indicates leading gas efficiency programs in these other jurisdictions were able to demonstrate rapid ramp up in the order of 1% to 1.5% of annual sales or more than two to three times that of Enbridge within the GTA.[45]

89. EFG concludes Enbridge could be capturing greater savings through more aggressive DSM programs to the point where it is achieving that of other jurisdictions (1% to 1.5% per year of annual sales) which could mitigate a

[44] Exhibit L.EGD.GEC.2, Page 6
[45] Exhibit L.EGD.GEC.2, Page 8

significant part of the need for Segment B.[46]

90. EFG estimates Enbridge's current DSM programs will produce approximately 14,000 peak hour m^3 savings in 2013 and 2014. The DSM ramp up proposed by EFG of 0.72% of annual sales in 2014 to approximately 1.2% in 2016 would result in 23,000 peak hour m^3 incremental savings in 2014 (a 60% increase over planned efforts) to roughly 37,000 m^3 incremental annual peak hour m^3 savings per year in 2016 and each year thereafter, with a significant portion of the ramp up from the residential sector.[47] In EFG's view, Enbridge has an enormous untapped potential from retrofitting residential buildings.[48] EFG believes other jurisdictions have demonstrated that these estimates of ramp up are achievable.

91. EFG claims its extrapolation from other leading jurisdictions and allocation of savings are illustrative only. EFG, like Enerlife, has not developed a new detailed bottom up DSM program design, plan and budget to achieve these savings as it was outside their scope of work. EFG suggests that participation in many existing programs could simply be increased by increasing financial incentive levels and/or marketing, whereas other programs such as the residential retrofit program would need to be redesigned but it could be done in relatively compressed timeframes.

92. Enbridge does not have confidence that targets identified by EFG are achievable.[49]

<u>Direct Testimony of Paul Chernick, Updated August 22, 2013</u>

93. GEC asked Mr. Chernick to review the extent that expanded DSM could defer or avoid some or all of the capital investments.

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[46] Exhibit L.EGD.GEC.2, Page 8,11
[47] Exhibit L.EGD.GEC.2, Page 12
[48] Exhibit L.EGD.GEC.2, Page 9
[49] T5, page 80

94. Mr. Chernick concluded the following[50]:

a. The Parkway West Gate Station, Segment A and the Union facilities cannot be avoided by load reductions.

b. Segment B2 (N/S) and possibly Segment B1 (E/W) appear to be avoidable through load reductions.

c. The deferral of Segment B requires forecast design peak load in the project area to be reduced by approximately 26,000 m3/hr annually.

d. Load reductions put forward by EFG (23,000 m3 at design peak hour) & Enerlife (30,000 m3/hr) would eliminate most or all of the load growth that Enbridge expects to create a supply problem at Station B. A curtailable arrangement with Portlands Energy Centre (PEC) and/or enhancement of the interruptible load program rates for industrial, commercial and apartment loads would be available to smooth the transition and top off any shortfall in DSM deployment.

95. Energy Probe submits the evidence is clear that Segment A distribution reinforcement pipeline cannot be avoided by load reductions.

96. With respect to Segment B, Enbridge's evidence is that the east-west portion of Segment B (B1) is required to take gas away from Albion and the north-south portion (B2) is needed to address load growth, the reduction in operational pressures[51] and it contributes to multiple supplies to the downtown core. Segment B provides looping and greater security of supply than a single source system.[52]

[50] Exhibit L.EGD.GEC1, Page 8-9
[51] Transcript 7, Page 20
[52] Transcript 7, Page 78

97. With respect to the project objective of lowering operating pressures, Enbridge's evidence is that both the Don Valley line and the NPS 26 operate at pressures greater than 30% SMYS and Enbridge has identified these XHP pipelines as high priority areas in its risk assessment process given the operating stress and the densely populated areas where they are located.

98. As noted in paragraph 60, Energy Probe accepts Enbridge's evidence that the pressure reduction in the Don Valley line is warranted.

99. In considering whether DSM could meet this objective, Enbridge provided DSM estimates that show that the DSM needed to lower the pressure as proposed in the NPS 26 and NPS 30 Don Valley line would be greater than a 20-fold increase in the GTA.[53] Lowering pressure has a significant impact on capacity. Enbridge estimates the capacity reduction associated with lowering the pressure is the equivalent of 160 TJ/day.

100. Enbridge's believes that the magnitude of conservation required to replace the capacity within the system due to the lowering of pressures on large diameter, higher pressure lines is too large to be achievable and the certainty of achieving the conservation targets is unknown. Enbridge states that magnitude and certainty make conservation a non-viable option for replacing capacity as a result of lowering pressures in existing infrastructure.[54]

101. Energy Probe acknowledges that load reductions may relieve the system and reduce pressure but agrees with Enbridge that the DSM required to offset 160 TJ/day of capacity is an order of magnitude beyond what could conceivably be offset through conservation initiatives given the evidence before the Board in this proceeding.

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[53] Exhibit I.A4.EGD.ED.18
[54] Exhibit I.A4.EGD.ED.18

102. With respect to offering PEC an interruptible delivery tariff or enhancing the interruptible load program rates to address any shortfall in DSM, Energy Probe submits that the evidence in this proceeding is insufficient to conclude that either are viable options at this time. Enbridge noted PEC is a firm customer with a 20-year firm contract and Enbridge has on record from the IESO that they are systematically important. PEC is a large combined-cycle power plant served from Station B, on winter design-peak days. The IESO confirmed that PEC has run on each day of the last four years during the peak winter day.[55]

103. Furthermore, Energy Probe notes no discussions with PEC have taken place to date. GEC has not had any discussions with PEC and indicates this would be the responsibility of Enbridge. With respect to current status of interruptible load, Enbridge noted an overall decline particularly within the GTA.

Timing of DSM

104. Enbridge requires approval of the GTA-project prior to mid-December 2013 in order for the project to meet the in-service date of November 2015. Enbridge indicates in the absence of the proposed facilities it will not be able to meet its design day conditions at Station B during the 2015/16 winter. As a result, the in-service date of November 2015 is critical to deliver the benefits of the GTA project.[56]

105. Energy Probe submits the evidence of ED and GEC focused on potential savings and suggestions were made on approaches Enbridge could follow but neither expert provided a DSM plan to meets its proposed objectives. Considerable work would be needed to be undertaken by Enbridge to redesign its DSM plan that would involve input from stakeholders and ratepayers. In Energy Probe's view ED and GEC's evidence

[55] Transcript 7, Page 82
[56] Enbridge Argument-In-Chief

does not adequately address the timing issue and the ability of Enbridge to implement their proposed DSM programs to meet the in-service date of November 2015.

106. During Energy Probe's cross examination, Enbridge indicated that it would need to have a proper geographically-based comprehensive potential study to understand potential in GTA and that it was not able to confirm with any confidence that an accelerated DSM program could be implemented in time to meet proposed in-service dates.[57]

107. Energy Probe submits that even if the Board ordered Enbridge to develop a greatly expanded DSM program, it is not conceivable that it could be designed and implemented with enough lead time to achieve the necessary savings within the timeframe available.

SUMMARY ON DSM ALTERNATIVE

108. Enbridge's system is designed at peak hour on a peak day.[58] In principle Energy Probe supports DSM and acknowledges that DSM could provide some benefits at peak in addition to annually. However, in considering the evidence in this proceeding, Energy Probe submits that due to the uncertainty raised around the following issues, DSM is not a preferred alternative to the proposed facilities, specifically Segment B:

- Uncertainty of impact of DSM on peak load resulting in many outstanding issue/concerns that need to be addressed;
- Uncertainty that Enbridge is able to meet the DSM customer penetration levels and savings identified by the ED and GEC's experts;
- Need for an expanded and aggressive DSM plan to be in place with specific load reductions to be realized before the November 2015 in-service date;

[57] Transcript 5, Page 126
[58] Tr. 7, Page 108

- Uncertainty that Enbridge could undertake significant changes and updates to its DSM plan and approach including consultation in time to meet the November 2015 in-service date;
- Need for further work by Enbridge to examine if curtailing supply to PEC is feasible or appropriate;
- Need for further work by Enbridge to examine the impact of an enhancement of interruptible rates;
- Inability of DSM to meet other project objectives beyond load growth;
- Timeframe required to increase DSM program is insufficient given the scale and the date the delivered results are required.

109. Enbridge screened out DSM early as an alternative to the proposed GTA Project for several reasons: it didn't meet the gas supply benefits and pressure reduction objectives and it couldn't achieve the second feed to downtown Toronto or the needed flexibility or diversity within the XHP system.[59]

110. Energy Probe agrees with Enbridge that in order to achieve the full range of GTA project objectives, the GTA Project is ultimately required.[60]

ISSUE A5. IS THE PROPOSED TIMING OF THE VARIOUS COMPONENTS OF THE PROJECTS APPROPRIATE?

Energy Probe's primary issue is that as noted in the Settlement Agreement, there is major uncertainty regarding the timing of the NEB approval of the Agreement and the cost consequences to EGD ratepayers if EGD proceeds with an NPS 42 pipeline and NEB approval does not happen, or is delayed.

111. EGD has requested approval of the GTA Project prior to mid-December 2013 in order for the project to meet the in-service date of November 2015. Enbridge's forecast is that, in the absence of the proposed facilities, it will not be able to meet its design day conditions at Station B during the 2015/16 winter. The November

[59] Transcript 5, Page 70
[60] Exhibit A, Tab 4, Schedule 7, Page 1

2015 in-service date is based on Enbridge's schedule of the activities required to complete the GTA Project 61 and no party took issue with the time requirements included in the schedule.

112. EGD indicates any delay in the proposed in-service date for the GTA Project will cost distribution ratepayers approximately $159 million for lost transportation savings in the first year alone.[61]

113. EGD seeks a Board decision by mid-December in order to proceed with procurement of long lead-time materials and resources required for the construction of the project. Enbridge continues to work toward the scheduled in-service date in order to realize the benefits of the GTA Project as quickly as possible, including very significant savings from 2015 to 2025.[62]

114. Energy Probe suggests EGD's expectations are simply not realistic. Which is the chicken and which is the egg? In our view, NEB approval of the Settlement Agreement is a ***prerequisite*** to approval of Segment A of the GTA Project Application as structured as a 42" combined transmission/distribution pipeline as proposed in the Updated Application of July 2013. Apart from uncertainties regarding the cost/Benefit of Segment A there are many components of the current Application that are contingent on approval of the Settlement Agreement (SA):

- Ability to contract with bidders from September 2013 Open Season (not allowed under SA).
- Ability to hold another open season for the remaining Albion Pipeline capacity (only after approval of SA).
- Upstream Facilities B_K and Parkway Compressor D to be built by Union.
- Downstream facilities to be built by TCPL (Kings North) (after approval of SA).

[61] Exhibit A, Tab 3, Schedule 9, Attachment 1, page 5, Table A5 (2016 savings).
[62] Exhibit A, Tab 3, Schedule 9.

115. What happens to Union and EGD LTC facilities applications if the NEB does not approve the Settlement Agreement and TCPL does not obtain Leave to Construct Connecting downstream facilities?

> MR. SHULTZ
> In the event that certain aspects, facility applications, weren't approved, I think there are other solutions that could be explored. I don't know what the form of them ultimately might be. I think we would try to find a rational, logical outcome that met the needs of everybody, TransCanada shippers and stakeholders, as well as Enbridge's.
> But really it is a lot of speculation to sort of go through the various scenarios.[63]

We suggest that this summarizes well the party's position -once Applications at the NEB are exhausted then Plan B will have to be worked out. We suggest that TCPL is in the driver's seat and will make the key decisions.

116. Should NEB approval not occur, or be delayed, this will unfortunately require the OEB to either decline to approve the GTA Pipeline application, approve Segment A as a 36" Distribution line, or approve an NPS 42 distribution line subject to the cost consequences being examined if/when the outcome of NEB approval is known.

117. In our submission, on the matter of the cost consequences it would be inappropriate to subject ratepayers to the risks and cost consequences from EGD's proposition that Segment A can proceed as a 42" pipeline based on in-franchise distribution requirements.
It is clear that at 42" it is oversized and costs too much to meet these requirements.

[63] Tr. Vol 9 page 82 line 14

118. Accordingly Energy Probe submits that the Board should in addition to its standard conditions, also Condition its Approval of the GTA Project upon EGD demonstrating, in its 2015 rate case that it has executed long-term transportation contracts for the Segment A EGD Albion Pipeline. The cost consequences of not providing this proof would be determined at that time.

IMPACT OF SETTLEMENT AGREEMENT ON NEED FOR GTA PROJECT SEGMENT A AND ECONOMIC COST/BENEFIT OF CHANGE TO SHORT HAUL FROM LONG HAUL TCPL TRANSPORTATION

119. The main rationales and need for Segment A of the GTA project as claimed by EGD are:

- diversify system entry points (Parkway Gate Station)
- reduce reliance on discretionary services (TCPL) and
- contract for transportation and gas supply from markets that are closer and lower in price. (Dawn and Niagara)

120. Ms. Giridhar explained further that,

> …in terms of our GTA requirements, I think I've said it numerous times, that the short-haul contracts that are being contemplated for the GTA project are really displacing discretionary arrangements that we used to have. These were non-renewable, short-term, firm, peaking kind of arrangements which, in the current environment, are neither reliable nor cost-effective, so we are looking for a transition step for a couple of years of taking FT long-haul, which we do know we'll be utilizing at a very low load factor.[64]

[64] 8Tr.99-100.

121. Ms. Giridhar commented on the change in market access as follows:

> The applications are structured to provide distribution service to the GTA and market access to downstream markets. Market access is required. These applications provide for an economical way to provide market access, through a single piece of pipe that can be upsized at low cost to meet downstream demands. We all know and understand that the alternative of building a smaller piece of pipe and then having to lay another pipe right next to it to create the market access that Quebec has been mandated to take is going to be a more expensive option. That's the extent to which the Board needs to consider the settlement terms sheet. It removes uncertainty. It allows for efficient build-up of facilities to meet distribution requirements and market access.[65]

122. Ms. Giridhar elaborated on the "orderly transition" contemplated by the Settlement:

> …you really need to take the bigger perspective here.
> It's not just what Ontario will bear, versus Quebec. It's not just what Union Gas would bear versus EGD; it's about making sure we have a structured transition to short haul and a result where there's equal opportunity and costs being shared by all of us. And that's what this term sheet does.
> And that's the extent of the relevance to the applications.[66]

123. With respect, it is **not** EGD's role to provide improved market access for Gaz Metro. That is the role of others --- Union as the operator of the Dawn-Parkway system and TCPL as the operator of the Parkway-Eastward transportation as part of the EOT ("Eastern Ontario Triangle") EGD's role is to look after the interests of its *in-franchise customers*.

[65] TCTr.(Sept.13/13)41
[66] Ibid 17

124. That having been said, the NEB RH-003-2011 Decision and the critical change that TCPL does not have a mandated requirement to serve, has major short and long term implications for EGD and its customers.

125. The Settlement Agreement attempts to provide a collaborative restructuring solution to the economic outcomes of RH-003-2011.

- Secures TCPL's Revenue Requirement 2015-2020
- Restructures TCPL Ratebase and Tolling areas
- Allows EGD increased market access by changes from Long Haul –Short Haul transportation. (400 tj/day)
- Reduces EGD and Union Landed Cost of gas

We note there may be significant opposition from other Mainline shippers, for example Manitoba Hydro Gas Division.

126. TCPL has confirmed that the Settlement Agreement alleviates a major financial impact on its earnings due to the LDCs shifting from long haul Mainline to short haul transportation. However, TCPL hasn't re-assessed the impact of the Settlement on the Union B-K and EGD GTA Projects which it previously characterized in its evidence as "uneconomic".

> MR. MONDROW:
> Mr. Schultz, you said three things. You said the costs being, I assume, the 20 million per year for six years, and the ROE decrease. That's what I pointed out to you a minute ago. And the third thing you said, although you said it in at least three ways, is a reallocation of the burden, and I'm using the word "burden". You didn't.
> Are those the three things that make these projects now economic when they weren't before, or were you simply wrong before? It's okay. I just need to know. Has something changed or not? And if so, what is it?

MR. SCHULTZ:

I think I was also saying that we haven't rerun the analysis to establish that we would call the economic threshold, and that that has been done by the LDCs.

MR. MONDROW:

Okay. So you were right before and you're not sure now. Is that what you're telling me?

MR. SCHULTZ: Well, I think that's probably fair. We said that things have changed. We haven't rerun this analysis, so we don't know what the actual result would be.[67]

127. At a high level, the Settlement "price" for EGD on behalf of its customers includes:

- Major uncertainty and potential opposition regarding **NEB approval of the Settlement Agreement (SA)** with significant collateral impacts on timing of Brantford-Parkway Project and GTA Project (EGD Albion Pipeline Segment A).
- EGD must **Contract for 360 tj/d FT instead of STFT at a higher cost** for winter 2014 (cost not quantified).
- EGD will pay **increased Long Haul Mainline Tolls** (119% of Compliance Tolls).
- Under Section 8.2 of SA EGD must **Contract for at least 13% of System Gas portfolio (265 tj/day)** for TCPL Long Haul -Empress to GTA.
- Under Section 13.2 (d) of SA, LDCs will pay **increased short haul tolls based** on a premium (155%) relative to the Compliance Tolls.
- Under Section 2.3 of SA LDCs will pay a **Bridging Contribution** from 2015-2020 (amortized for up to 16 years i.e. to 2030).
- Be exposed to the long term (after 2020) shortfalls in the **TCPL LTTA.**

[67] Tr Vol 9 Page 105

EGD's total forecast increase in TCPL tolls flowing from the Settlement Agreement is $66.4 million/year.[68]

128. The claimed financial benefits, are contingent, first on NEB approval of the Agreement, and second on future gas cost reductions estimated at $50-68 million a year. These gas cost reductions are based on forecast lower Ontario landed gas prices, based on price differentials of $0.50-$1.50 between Dawn and Empress based on Marcellus and similar sources and WCSB gas[69].

SETTLEMENT AGREEMENT NOT APPROVED BY NEB, DELAYED OR CHANGED

129. If the NEB either does not approve the Settlement, or there are delays or major changes then what is "Plan B"?

> MR. MONDROW
> If the Board [OEB] approves your projects, Mr. Isherwood and Ms. Giridhar, and the NEB rejects the Settlement, what happens to the approvals given here? Anything?
> MR. ISHERWOOD:
> I think to the extent that the NEB doesn't approve the settlement, then I think the only project that would be potentially at risk of going forward would be Union's Brantford-to-Kirkwall.
> We've asked for -- in that application we've actually asked for an extra year to construct, out to '16, so I think the rest of the projects would still be required.[70]
> MS. GIRIDHAR:
> Mr. Mondrow, I believe I addressed this in my opening remarks yesterday. The relevance the settlement agreement is that it has charted a path forward for market access. This Board, in a ruling to Union Gas last year or the year before -- last summer, urged the LDCs to work with TransCanada on a rational expansion of

[68] Undertaking J9.
[69] Undertaking J9.1
[70] Tr Vol 9Page 105

our systems.

We have done that. We have identified a path forward from market access. The GTA project was originally filed as a distribution project of an NPS 36. It is now an NPS 42. For less than a 10 percent incremental cost, we're able to accommodate that market access and provide significant cost savings to our customers that's identified in an undertaking response to Energy Probe.

130. Union indicates that if the NEB does not approve the Settlement it will not proceed with the B-K portion of its project.

MR. MILLAR:

Sorry, just to repeat, the condition I'm suggesting or asking you to consider would be the Board says do not start construction until the NEB has approved the Kings North project.

MR. ISHERWOOD:

We would not start construction, but we may be incurring costs before that, in terms of buying pipe or creating easement, that type of thing, which you would have to do to be ready for a '15 in-service.[71]

In our view, Union's contingent position on the B-K project **is** in the public interest.

131. Regardless of NEB approval or not, EGD is still planning to proceed with a 42" Albion-Maple (Segment A) pipeline that is way oversized (2000 tj/d) relative to distribution requirements (800 tj/d) and costs $31 million more with the difference to be paid for by distribution customers.

MR. MILLAR:

But there are some interdependencies between them, the same way. What would Enbridge's view be with respect to a condition saying wait on Kings North before

[71] Tr Vol 9 Page 136

you start GTA segment A? I assume your position will be you don't support that?

MS. GIRIDHAR:

We would not support that. I think the evidence in this case has been quite clear that Enbridge needs segment A to meet the distribution needs in the GTA. The Kings North project facilitates market access for the rest of Ontario and Quebec. It is Enbridge's position that the NPS 42 is justified, can be justified even on distribution needs to be economically feasible.

132. We strongly disagree with EGD's position.

- First EGD has not clearly demonstrated the EGD Albion Pipeline is economic--EGD has not filed a separate E.B.O. 134 analysis for Segment A, so the Board does not know whether or not it is economic.
- Second, even if the 42" Albion Pipeline is "economic" for combined transmission and distribution services, then it will directionally be less economic (lower PI) for distribution only. This is because the $20.2 million/yr. of forecast transmission revenue would not occur.
- Last, EGD is asking distribution customers to pay the opportunity cost of a 42" Segment A pipeline, presumably because they may receive a benefit from transmission revenue in the future.
- In fact a 36" pipeline with 1200 tj/d capacity would meet all EGD distribution needs as well as Union, GMI and EGD's EDA cross franchise requirements provided TCPL provides Kings North downstream connectivity.

133. In our view, the Board should find that EGD's default position in the event of the NEB not approving the Settlement, ***is not in the public interest***. Accordingly As noted above we request that the Board condition any approval of the GTA Project to protect ratepayers from any negative cost consequences.

ISSUE D1 DO THE FACILITIES ADDRESS THE OEB ENVIRONMENTAL GUIDELINES FOR HYDROCARBON PIPELINES AS APPLICABLE?

134. Enbridge filed an Environmental Report (ER) prepared by Dillon Consulting Limited (Dillon) dated September 30, 2012 for the GTA project. Dillon indicates the ER conforms to the Board's Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipeline and Facilities in Ontario, 6th Edition, 2011 (Environmental Guidelines).

135. The Board's current Guidelines provide direction on public consultation, route or site selection, impact mitigation and mitigation implementation and monitoring activities. Enbridge filed and Environmental Report Amendment in February 2013 to address changes in pipe size, the initiation point and public input on the proposed changes. In July 2013, Enbridge filed a second amendment to the Environment Report due to changes in the starting point of Segment A and the addition of a 1.5 km route extension.

136. As part of its work, Dillon undertook a route evaluation process, environmental impact study and mitigation analysis along the preferred routes, a route selection process, a stakeholder consultation program and further analysis of the environmental impacts and mitigation measures along the preferred route. The environmental impact analysis considered the physical environment, natural environment, socio-economic environment, land use, infrastructure, economics, tourism and recreation, First Nation and Metis Communities, archaeological and heritage resources, community services, planning policies and waste disposal and potentially contaminated sites.

137. In addition, a cumulative effects analysis was undertaken that identified mitigation and protective measures. Dillon also provided inspection and monitoring recommendations for pre, during and post construction that included the responsibilities of the Environmental Inspector for the project.

138. Dillon indicates that its mitigation recommendations along with Enbridge's Construction and Maintenance Manual 2012 and its Environmental Guidelines for Construction, June 2012, should effectively serve to protect the environmental features along the referred routes. Dillon recommends that the mitigation measures from the ER along with Enbridge's construction policies should be included in the contract specifications. Dillon also notes that the use of a qualified Environmental Inspector will help reduce disturbance to the local environment during pipeline construction. Dillon does not anticipate any long term impacts from the construction and/or operation of the proposed pipelines based on the mitigation measures recommended in the ER.[72]

139. The ER Amendment reviewed the potential changes in cumulative effects and concluded that the changes are expected to result in reduced construction impacts.[73] The second ER Amendment reviewed the cumulative effects of the proposed project changes and concluded that the potential for cumulative effects is the same as that presented in the ER and ER Amendment.[74]

140. As part of this proceeding Energy Probe asked interrogatories on the ER regarding the route selection process, cumulative effects analysis, stakeholder consultation activities and input from interested parties and any outstanding issues.

141. In its Argument-In-Chief, Enbridge indicates the GTA Project fully complies with the Board's Environmental Guidelines. In addition Enbridge states it is fully committed to implementing the mitigation measures recommended by Dillon.[75]

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[72] Dillon GTA Project Environmental Report, Executive Summary, Page xiii
[73] Dillon GTA Project Environmental Report Amendment, Page 6
[74] Dillon GTA Project Environmental Report Amendment #2, Page 12

[75] Enbridge Argument-In-Chief, Page 21

142. In considering the extensive evidence on the record regarding environmental impacts and Enbridge's commitment to implement Dillon's recommendations, Energy Probe is satisfied Enbridge's GTA Project facilities address the OEB's Environmental Guidelines.

143. Energy Probe suggests three additions to the wording of the Conditions of Approval for this project under Issue D6 for the Board's consideration.

ISSUE D6 IF THE BOARD APPROVED THE PROPOSED FACILITIES, WHAT CONDITIONS, IF ANY, ARE APPROPRIATE?

144. In section 9 of the original ER, Dillon provides a listing of the agencies where notifications, permits and approvals may be required for the GTA project. Energy Probe notes many permits, approvals and authorization include additional conditions that Enbridge must satisfy some of which could address mitigation of environmental impacts from the project.

145. In order to ensure the any additional conditions are adhered to Energy Probe suggests an addition to the wording under 1. General Requirements (paragraph 1.3) as follows:

1.3 Enbridge shall implement all of the recommendations of the Environmental Report filed in the pre-filed evidence, and all the recommendations and directives identified by the Ontario Pipeline Coordinating Committee ("OPPC") review. **Enbridge shall also adhere to the conditions of all permits, approvals, licences, certificates and easement rights applicable to the project facilities.**

To allow for a broader scope of changes that may occur, Energy Probe suggests the following wording addition in 1.4.

1.4 Enbridge shall advise the Board's designated representative of any proposed material change **including but not limited to changes in** construction or restoration procedures and, except in an emergency, Enbridge shall not make any such change without prior approval of the Board or its designated representative. In the event of an emergency, the Board shall be informed immediately after the fact.

146. In addition, Energy Probe suggests the following addition to the wording under 4. Other Approvals (paragraph 4.1) to further clarify that the Board is the party to receive the list:

4.1 Enbridge shall obtain all other approvals, permits, licences and certificates required to construct, operate and maintain the proposed project, shall provide a list thereof **to the Board**, and shall provide copies of all such written approvals, permits, licences and certificates upon the Board's request.

147. Energy Probe recommends the following special Conditions of Approval:

a) The Board place a special Condition that EGD demonstrate that it has entered into long-term transportation contracts for the EGD Albion Pipeline (Transmission capacity 1200tj/d on Segment A). The cost consequences of this to be examined in EGD's 2015 rate case.

b) If EGD offers capacity on Segment A Albion transmission pipeline to in-franchise unbundled distribution customers the cost allocation and rates be subject to review in EGDs 2015 rate case.

COSTS

Energy Probe has participated actively in the prehearing and hearing stages of this Application and has managed its time in an efficient manner in cooperation with other intervenors.

Accordingly, we request that the Board grant a Cost Award to reimburse 100% of our legitimately incurred costs.

Respectfully Submitted at Toronto this 15th Day of November 2013.

Roger Higgin, SPA Inc.

and

Shelley Grice

Consultants to Energy Probe Research Foundation